Some Context for Ballot Measure 1
2020 Oil Tax Initiative

By
Brett Watson

Institute of Social and Economic Research
University of Alaska Anchorage
3211 Providence Drive
Anchorage, Alaska 99508

10/14/2020

UAA Institute of Social and Economic Research
UNIVERSITY of ALASKA ANCHORAGE

Executive Summary

Ballot Measure 1 (BM1) is a citizen's initiative on the November 2020 ballot. The initiative, called the 'Fair Share Act' by its proponents, would raise petroleum production taxes in the largest oil fields in the state of Alaska. This paper attempts to provide some context for the initiative by examining three key questions. First, what changes does the initiative make? Second, what role might these changes have in addressing the state's current fiscal situation? Finally, how might these changes affect production and investment in the Alaska oil industry?

The measure increases taxes on the larger and older fields on the North Slope, leaving rates for smaller, newer, or Cook Inlet areas unchanged. Today, the fields affected account for 80-90% of oil produced in Alaska and include Prudhoe Bay, Alpine and Kuparuk. Like the existing tax structure, the new tax rate depends on the economics of oil. At prices of $40 and with current costs, producers currently pay an average of $1.08 per barrel in production taxes. Under the proposed higher rates, they would pay $2.69 per barrel.

Ballot Measure 1 'ringfences' large oil fields. This prohibits a company's investment in new fields to be taken as tax deductions on their profits in the older fields. Instead, the company will have to wait until the new fields are profitable enough on their own to deduct the expenses incurred to develop them. The measure also requires a monthly tax rather than annual tax calculation. Because oil prices can vary over the course of the year, and the tax rate increases as prices rise, the tax will capture more revenue on the upswings than it misses on the downswings. Finally, the measure would require public disclosure of certain tax documents used by the Alaska Department of Revenue in determining a company's tax liability.

Around current oil prices, the initiative is likely to capture between $200-500 million in additional annual tax revenue in the near term, assuming no change in production activity. This compares to the approximately $1B deficit in FY21 ($2.2B had a PFD been appropriated using the statutory formula). Between 2021 and 2029, the initiative might raise an additional $2 billion given current projections of prices, production, and costs.

Evidence from the economics literature suggests taxes in general, and oil taxes specifically have some negative impact on investment activity, but the magnitude of these impacts is difficult to extrapolate to the circumstances of this tax change. Instead, we estimate that the rate of projected declines in production would need to approximately double for the state to collect less revenue under Ballot Measure 1 than under the current tax structure.

The actual long run effects of Ballot Measure 1 will depend on several factors for which there is a great deal of uncertainty. These factors include the future demand for oil, the quantity of North Slope resources, extraction costs both in Alaska and in other oil-producing areas, and how the new revenues will be spent by the State. It is unlikely that Ballot Measure 1 will be the only required solution to the State's fiscal problems, but oil tax changes could play some role in a sustainable budget.

Table of Contents

Contents

0. Purpose and Scope

This report seeks to provide context to the Ballot Measure 1 proposition. The analysis in this paper focuses mostly on the short to medium term revenue impacts to the State of Alaska from the proposed changes in the measure. The report provides a summary of the text of the measure, a brief history of past tax changes, an analysis of the revenue impacts of its components, a review of relevant academic literature, a summary of recent trends in the Alaska oil industry, and some comments about future uncertainty.

This analysis does not conduct economic impact analysis of Ballot Measure 1, (such as what might be done using multiplier estimates and input/output techniques). Nor does it attempt to evaluate the change in project economics using techniques such as discounted cash flow analysis. Such analysis has been conducted by others and these include Czapla and Gray (2020) and IHS (2020). While this report discusses such impacts qualitatively by drawing from theoretical and empirical economics, it does not quantify either.

I. Technical details of Ballot Measure 1

I.A. Current Tax Schedule

Ballot Measure 1 keeps the overall structure established in 2013 under Senate Bill 21 (SB21), but changes tax rates and per-barrel credits in ways that substantially increase production tax liabilities at all prices. To understand the mechanics of Ballot Measure 1, you first need to understand the current structure.

Under the current structure, companies pay the higher of a 35% tax on their net profits (net tax), or a minimum tax on their gross revenues. That minimum tax varies from 0% to 4%, depending on oil prices. The net profits tax owed is reduced using per-barrel tax credits, which vary depending on when, where, and how the oil is produced and current oil prices.

The minimum tax rate is a function of the Gross Value at Point of Production (GVPP.) The Gross Value at Point of production is the delivered Alaska North Slope (ANS) price minus the cost of transportation. The relation between the GVPP and the minimum tax is:

GVPP	<$15	$15-17.5	$17.5-20	$20-25	$25+
Minimum Tax	0%	1%	2%	3%	4%

The cost of transportation from the North Slope to the west coast of the US is approximately $10 per barrel at present, so the GVPP is currently about $10 less than the posted ANS price.

The net tax is a 35% tax on a producer's net income, which is modified by the producer deducting per-barrel credits and certain deductions (Gross Value Reductions) that a producer can take given that they drill in certain times/places. Net income is a function of oil prices, transportation costs, and production costs. Per-barrel credits reduce a producer's net tax liability for each barrel of oil produced. There are two types of per-barrel credits, of which Non- Gross Value Reduction credits are the most important. Non-GVR credits cannot be used to reduce tax liability below the minimum tax. As show in the table below, these credits are based on the GVPP price of oil and phase out as oil prices rise above $80/bbl GVPP. The per-barrel production credits are $8/bbl for gross value per barrel below $80. They are phased out as gross value per barrel increases according to the following schedule:

Gross value (GVPP $/bbl)	<80	80-90	90-100	100-110	110-120	120-130	130-140	140-150	150+
Credit/bbl Value	8	7	6	5	4	3	2	1	0

Because the net tax depends on a producer's net income, the two most important determinants of the production taxes owed are oil prices and lease costs. Figure 1 shows the current tax schedule for a representative tax payer under various prices and three lease cost scenarios. Under certain assumptions, the production tax begins to phases in as oil prices rise above $15/barrel at the point of production, or about $25/barrel ANS at current transportation costs of about $10/barrel as shown on the figure. The full minimum tax of 4% is reached at $25/barrel at the point of production (~$35 ANS). Depending on a firm's lease costs, the minimum floor rate will set the amount owed until prices rise to ~$55/bbl in the $15 lease cost scenario to ~$90/bbl in the high scenario. The per barrel credits begin to phase out as prices rise higher, eventually falling to 0 when price at point of production is above $150/bbl.

I.B. How Ballot Measure 1 changes SB21

The proposal has three main features that would apply to companies operating in certain oil fields in Alaska. It would raise production tax rates on what we will hereafter call "40/400" legacy fields that currently include Prudhoe Bay, Alpine and Kuparuk (80-90% of current production). It limits use of tax deductions/credits from other ("new") fields or *between* legacy fields by establishing separate taxable entities for each field. This is commonly called "ringfencing" in discussions of the ballot measure.   I It also creates a public disclosure requirement for certain documentation used to calculate these taxes.

"40/400"

The "40/400" is a threshold established by the proposal designed to target certain large fields on the North Slope. To be affected by the measure, a field must be currently producing "40" thousand barrels of oil per day and have cumulatively produced "400" million barrels of oil over its lifetime. Currently, three areas (as defined by AK Department of Revenue) meet this designation: Prudhoe Bay (200/12,500), Kuparuk (70/2,500), and Alpine (50/600). AK Department of Revenue also defines Prudhoe Bay and Kuparuk satellite areas and it is unclear whether these would be treated together or separately with their respective main fields for the purposes of BM1. The Prudhoe Bay satellites (45/600) would currently surpass the threshold on their own, but Kuparuk satellites would not (30/300). Collectively, these fields account for between 80-90% of production in Alaska. Other projects currently being explored and developed may eventually meet the thresholds as well. For example, if certain production and size projections from ConocoPhillips are met (100,000 bbls/day starting in 2025), the Willow project would be subject to the BM1 regime after 10 years of production.

Note there is some ambiguity about exactly how production would be grouped for this calculation. For the purpose of this analysis, we adopt AK DOR area definitions. This analysis further assumes Prudhoe Bay and Prudhoe Bay satellites are grouped together, as are Kuparuk and Kuparuk satellites.

Increased production tax rates

Ballot Measure 1 (BM1) maintains a similar production tax structure of the 2013 Senate Bill 21 (SB21) but amends it by increasing the tax rates on the qualifying 40/400 fields. Unlike the previous changes to production taxes, BM1 would increase the tax rates under virtually all oil prices and producer costs, and maintains a zero tax rate when GVPP is zero.

Proposed Tax Schedule

The proposal in Ballot Measure 1 makes changes to all three key elements of the SB21 structure. The measure:

1. eliminates per-barrel credits,
2. raises the minimum tax rates to 10-15% (depending on prices), and
3. adds a higher marginal tax bracket of 15% to the net tax when oil prices are high.

We present the proposed tax schedule in Figure 1. Unlike the current schedule, the proposed minimum gross tax schedule starts at 10% and does not phase in at very low prices (eg ANS<$25/bbl), as occurs under the current structure. The proposed measure will increase tax rates over the current schedule in every case where GVPP is positive. The new 10% minim tax will apply when prices are less than $30/bbl ANS in any of the three lease cost scenarios. When lease costs are low, the 35% net tax will take effect at lower prices than in the current schedule as the tax per-barrel credits no longer apply. The additional 15% marginal tax takes effect when the net price (ANS price minus transportation and lease costs) exceeds $50. Only when prices and lease costs are relatively high do the step-increases (1 percentage point per $5/bbl) in the proposed minimum tax become relevant.

Ringfencing

The measure requires that a company's production in each of the fields that meet the 40/400 threshold be treated separately from each other and from other Alaska fields for the purpose of calculating their state taxes. This prevents deducting expenses incurred outside a given 40/400 field against revenues earned inside that field. For a firm with operations in all three current 40/400 fields and elsewhere, this would entail four separate calculations.

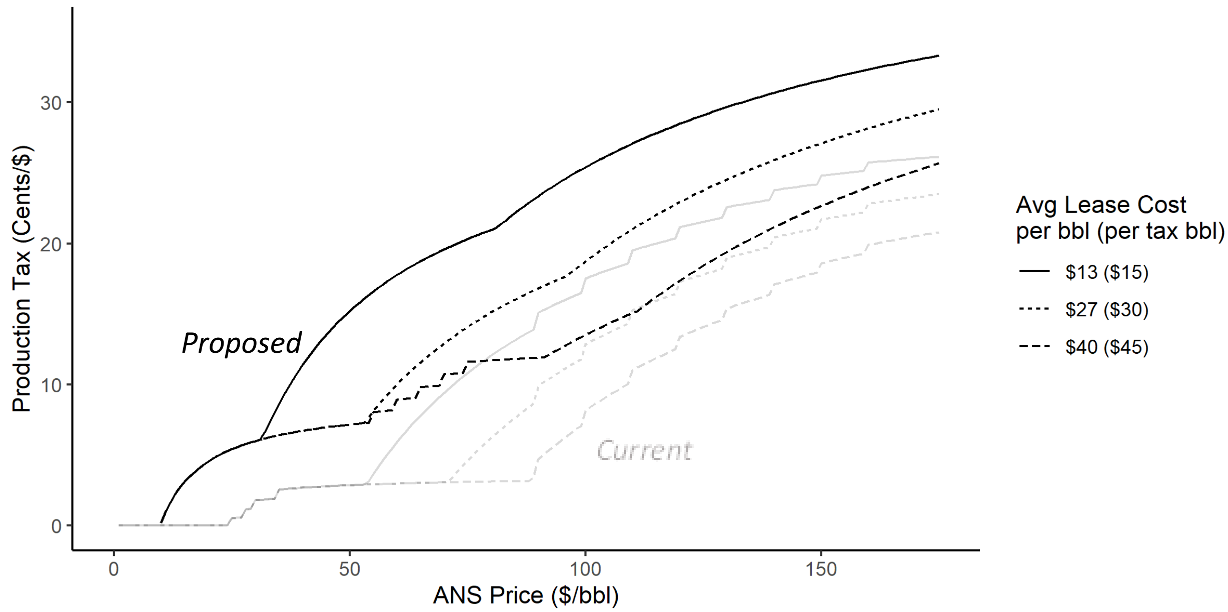
Monthly Taxes

Instead of taxes calculated on an annual basis, the measure would require companies to calculate their taxes monthly for each of the three fields. The progressive tax structure causes any month-to-month volatility in oil prices around any "switching points" (e.g. from the minimum gross tax to the net profit tax) to increase revenue for the State.

Tax document disclosure

The measure would require documentation that is provided to AK Department of Revenue in preparing tax calculations to be made public.

Figure 1: Current and Proposed Effective Production Tax Rates



Source: Author's calculations. The vertical axis is the effective production tax rate measure in cents per dollar of gross value at point of sale (ie ANS price). Cents per dollar is equivalent to a percentage rate. The current (greyed) and proposed (dark) production tax schedule (cents/dollar ANS) with various prices and average lease costs. Average total lease costs are in $/barrel or ($/taxable barrel) units for comparison. The schedules assumes transportation costs of $9.78/taxable barrel, an effective royalty rate of 11%, and that the fraction of gross-value-recovery production is 2%. However, all production is assumed to generate a non-GVR sliding scale credit based on price at gross value of point of production for the current schedule.

II. Oil production and State of Alaska Revenues

II.A. Sources of State oil tax revenue

The State of Alaska collects revenue from petroleum through four main channels: royalties, property taxes, production taxes and corporate income taxes. In 2019, royalties accounted for approximately $1.1B in revenue, the production tax $600m, the corporate income tax $220m and the property tax $120m. Further, some local governments also collect significant revenues from petroleum property taxes. Each of these channels is has a different justification, structure, and associated incentives. While the text of Ballot Measure 1 only directly affects the structure of the State's production tax, it could have spillover impacts into the other channels.

Royalties

Royalties are the payments made to a mineral resource owner when a resource is taken. The concept of mineral royalties has existed for centuries. In feudal societies, the king was the owner of all mineral resources so in order to mine gold or silver, the king had to be paid a 'royalty' in exchange. Royalty payments take many forms. They can be negotiated or auctioned one-time payments, they can be flat fees based on the quantity taken, they can be based on the value (quantity times price), or some combination.

Alaska's oil resources are owned by a combination of federal, state, tribal, and private interests. Most production since 1970 has come from oil resources owned by the state of Alaska in areas like Prudhoe Bay. As the owner of the resource, the State of Alaska typically collects a one-time 'bonus' payment at the beginning of exploration and development and then a 12.5% royalty on the value of production thereafter. While royalties provide the state of Alaska revenue, they are not themselves taxes but compensation for transferred ownership privileges, similar to state sales of lands or surplus equipment.

Most oil production in other U.S. states tend to come from privately owned mineral rights. In these cases, firms looking to develop an oil resource negotiate directly with the private mineral rights owner to find a structure of compensation. Like the state-owned resources in Alaska, these tend to involve one-time and upfront bonus payments, then flat rate royalty on the gross value of production.

Production Taxes

Ballot Measure 1 directly affects oil production taxes. Unlikely royalties which are based on the notion of ownership, Alaska's production taxes are based on the notion of sovereignty. Alaska's production taxes are one form of a severance tax that are common tax instruments in U.S. states which have extraction of non-renewable resources like oil, gas, coal, or gold. The concept of a severance tax is designed to compensate a jurisdiction for the irreversible act of 'severing' a resource from the ground.

Severance taxes in the United States take various forms. Some are based just on the quantity of resource extracted, some are based on the value (price times quantity), some vary by extraction methods or costs, and others vary tax rates as resource prices change.

While Alaska has made changes to its oil production tax since it was implemented, there have been several consistent features. First, the tax is based on value of oil (price times quantity), rather than just the quantity produced. Second, the tax has recognized that the value of oil when it reaches market (i.e. California) is different than the value in the ground because of the cost to drill, produce, and transport, so adjustments are made to the value to reflect these costs. Third, the production tax typically applies unevenly over time, location, or well type to incentivize certain types of investment and production activity. Finally, the production tax as often attempted to capture the 'rents' or pure profits from oil by increasing the tax rates when profits are high. The current oil tax structure was passed as part of Senate Bill 21 (SB21) in 2013 displays each of these features.

Corporate Income Taxes

As a sovereign, Alaska levies a tax on C-corporations operating in the state. Because of the specific importance of oil and gas corporations operating in the state, special considerations are applied when determining the Alaskan-portion of these oil and gas businesses. These provisions establish a process of "apportionment" that uses the worldwide income of the oil and gas companies and apportions it to Alaska on the basis of property, production, and sales in Alaska to its corporation-wide totals. Taxes on oil and gas companies typically accounts for a very large share of total corporate income taxes. For example, the state collected $110 million in non-petroleum corporate income taxes in 2019 compared to $220 in petroleum corporate income taxes. S-corporations and limited liability corporations (LLC) are generally exempt from Alaska's corporate income tax. This distinction is relevant because of the recent sale of BP (a C-corporation) assets to Hillcorp (an LLC.) The maximum marginal tax rate for Alaska's corporate taxes is 9.4%.

Property Taxes

Like other forms of property taxes, the State collects a tax based on the assessed value of property used in the exploration, development, production, and transportation of oil and gas. The tax is 2% (20 mills in property tax jargon) of the assessed value. When the property is located within a local jurisdiction, that jurisdiction may impose a property tax on the assessed value at the same rate as other property is taxed in the community. The amount taxed by the local government up to the 20 mills is applied as a credit for the state's tax.

Tax Tapestry

The pattern in production taxes and oil prices highlights an important feature of the petroleum revenue structure for the State of Alaska, namely that the four channels respond differently to changes in the environment. Property tax revenues tend to smaller but more stable over time, while production taxes respond with more volatility to prices and producer costs. Just as the Permanent Fund invests in a diverse set of assets, having a diverse basis for taxation even for a single industry helps to provide additional security for the state's revenue.

Apart from pure diversification, the more complex tax structure enables the state to purse multiple objectives at simultaneously. The state wants to collect revenues today, while encouraging investment to secure future revenue. It wants to capture rents, but without discouraging employment. The state wants to balance shared price or exploration risk with oil producing firms. The state wants to minimize environmental damage. The more objectives one pursues at the same time via the taxes or regulatory policy, the more individual taxes or policies are required (i.e. Tinbergen rule).

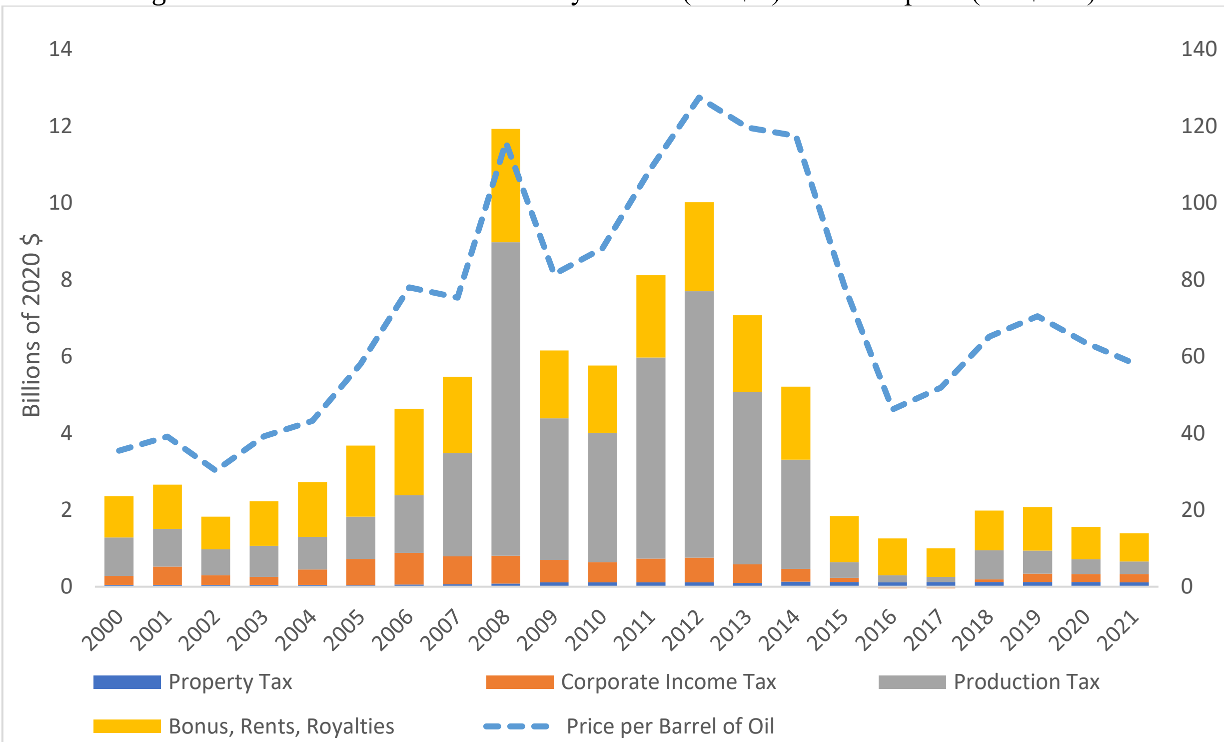
Understanding how these revenue sources interact is also important to understanding the potential impact of Ballot Measure 1. Some interactions are mechanical. For instance, the corporate income tax is assessed on net earnings, which are earnings after other taxes. If production taxes are increased, corporate income (and corporate income tax revenue) decrease. Other interactions are based on firm's responses to changes in taxes. For example, Ballot Measure 1 raises taxes in 40/400 areas where the current mineral owner is the State of Alaska. If producers respond to the tax change by shifting production into non-40/400 federal areas, the increase in production taxes may be partly offset by a decrease in royalty revenue. Using multiple revenue instruments can offset some of these effects.

Recent Trends in Petroleum Revenue

Over the last 20 years, royalties and production taxes have provided most of the state's petroleum revenue, while the corporate income taxes from petroleum producers and the petroleum property tax make up smaller portions (see Figure 2). During the high oil price period of 2007-2014, production tax revenues were significantly higher. When oil prices were low in the 2015-2017 period, production taxes were also very low. Changing the oil production tax structure from the 2007 ACES framework to the 2013 MAPA framework also had some effect on revenues Goldsmith (2014).

Newer areas of exploration and development activity have tended focus on non-State oil resources, notably the National Petroleum Reserve and in offshore areas. Federally controlled areas like the National Petroleum Reserve have some stipulations for sharing royalties with the State, but these provide lower rates to the State and often some restrictions on how money is used. Because of these factors, oil royalties are likely to play a diminishing role in the future of State revenue.

Figure 2: State Petroleum Revenues by Source ('20 $B) and ANS price ('20 $/bbl)



Source: 2018 Fall Revenue Sourcebook From Alaska DOR for years 2000-2018. 2019 Fall Sourcebook for years 2019-2021; 2019 is preliminary data; 2020 and 2021 are forecasts. State petroleum revenue by source (left axis) are billions of dollars in real 2020 terms. ANS price per barrel is in real 2020 $/bbl.

II.B. History of oil taxation in Alaska

Alaska has been governed by four main oil production tax regimes over the last 20 years. This includes Economic Limit Factor or ELF (1977-2006), the Profit-based Production Tax or PPT (2006-2007), Alaska's Clear and Equitable Share or ACES (2008-2013), and More Alaska Production Act MAPA passed as SB21 (2013-). Intermittent modifications to these regimes have also occurred over this period. Each of these regimes was enacted with specific goals in mind and were changed when the language of the policy did not meet intended goals, when circumstances changes, or when the goals themselves changed.

ELF (1977-2006)

The principle for Alaska's first oil production tax regime was to encourage wells to keep pumping as long as there was oil in the ground. This is motivated in part by the physics of oil reservoirs, which are under pressure. When a well taps into the reservoir, the pressure helps the oil rise to the surface. As the well produces over time, the pressure quickly declines making it more difficult and expensive to extract remaining resources as oil needs to be pumped out. Eventually, the rising cost of pumping exceeds the value of the remaining oil and the well is shut-in. ELF was designed with this pattern in mind and was based around the age of producing fields, with the tax falling to zero for older fields. Because the State earns a royalty on the gross value of oil, from its perspective it makes sense to encourage production of oil while wells are active rather than leave the resource in the ground where it would almost surely never be recovered.

PPT (2006-2007)

Profit-based Production Tax (PPT) was designed to address four issues with ELF. First, ELF was based largely on physical characteristics of the field so it relied on geological information in order to properly administer. PPT was based on economic characteristics of the field, which was seen as somewhat easier administratively. Second, oil production tax revenues had been declining and were projected to continue declining. Third, the state wanted to provide additional incentives for investment. Fourth, the state wanted to share more risk with the firms, taking more tax revenues than ELF at high prices but less revenue than ELF at low prices.

ACES (2008-2013)

As oil prices were rising in the mid-2000s, Alaska's Clear and Equitable Share (ACES) was seen as a way for the state to capture more of these rents in the new high-price environment. ACES imposed a very high and progressive tax structure. It also introduced capital expenditure credits, designed to increase investment dollars spent. Like PPT, the progressive structure of ACES meant that taxes collected would be more sensitive to oil prices. The implementation of ACES corresponded to a very high price oil period, and the State collected substantial production tax revenues over this period.

MAPA (2013-present)

The current oil tax regime was passed as part of Senate Bill 21. The More Alaska Production Act (MAPA) was designed to do two things. First, many saw the very high rates enacted by ACES as placing Alaska oil at a competitive disadvantage relative to other oil producing jurisdictions. Second, the credit structure in ACES incentivized capital expenditures, but not necessarily production. To address continued declines in North Slope oil production, MAPA provides per-barrel-produced credits to offset the tax liability.

Cashable Credits

In parallel with these for major changes to Alaska's oil tax regime, there have been a number of cashable tax credit incentive programs that have been enacted and repealed. According to the Fall 2019 Revenue Sourcebook (Table 8.2), these programs have been valued between $250-628 million annually over the period 2010 and 2015. Many of these programs were reduced or eliminated as part of HB 247 in 2016 and HB 111 in 2017. The State currently has a balance owed on these credits of over $700 million. Note that these cashable credits are distinct in form and function from the per-barrel credit mechanism as part of MAPA.

II.C. Comparison of Oil Tax Regimes Over Time and to Other States

To add context to the oil tax regimes that Alaska has implemented, the following two sections compares these structures to one another and to the structures in other U.S. states by comparing effective production taxes (severance taxes).

Effective tax rates are useful because they capture the total effects of complexities like progressivity, different rates by production types, and credits or other incentives for certain types of investment or production. At the same time, abstracting across these complexities does place limitations on the comparison. Oil price levels need to be considered when comparing tax regimes that tie rates to prices (e.g. through more progressive rate structures). Further, taxes are often designed to provide certain positive incentives (or limit negative incentives) for firms. Effective tax rates provide a way to understand how firms will respond to both the incentives of the tax and other market and geological conditions that were in place at the time. The comparisons presented here should be interpreted with caution. The effective rates experienced in one place during one time with a certain tax structure are unlikely to be the effective rates in another place or time had the structure been in place there.

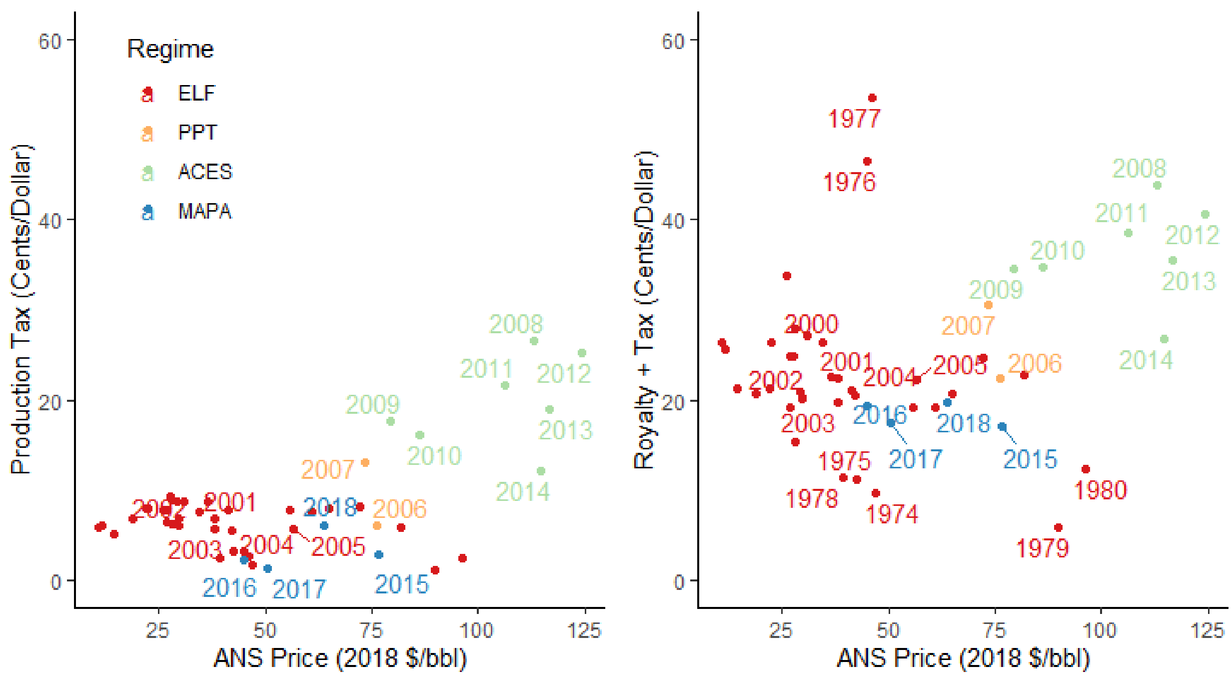
Historical Comparison of Oil Tax Regimes

The left panel of Figure 3 presents the actual effective severance tax rates and oil prices over the Alaska oil production tax regimes in place from 1970-2018. Presented in this way, the progressivity of the ACES structure relative to ELF is quite apparent. The right panel of Figure 3 presents the fraction of state revenues of gross revenues (ANS price times quantity). These state revenues are inclusive of the four major channels of oil revenue for the state, most importantly, royalties and production taxes.

The standout years of 1976 and 1977 on the right panel are due to lease bonus payments made during the development of the North Slope when large initial investments were being made but production was low.

One difficulty in evaluating based on the observed experience was the very high prices that were experiencing coinciding with ACES. Five of the seven years ACES was in effect saw real 2018 ANS prices above $100/bbl, no other regime experienced prices at this level. Analysis by Goldsmith (2014) explores effective tax rates of ACES and MAPA under a host of potential scenarios. Had prices been closer to the $50-60/bbl range and lease costs remained in the $30-40/bbl range, effective ACES tax rates would have been historically low, between 0-10%.

Figure 3: Tax and Revenue Rates Under 1970-2018 Production Tax Regimes



Source: Author's calculations. 2018 Fall Revenue Sourcebook from Alaska DOR. The effective production tax rate is calculated as the actual total production taxes collected divided by the gross value of oil produced. Overprinted years (1981-1999) for ELF are not labeled.

Impacts of Historical Tax Changes

Apart from current revenues, changes in taxes have also been motivated by adjusting incentives for production and investment. The multiple oil-revenue channels mean that lowering production tax rates may incentivize production which in turn increase royalty revenue. At the same time, successful exploration and development provides for future production and state revenues. In this way, the State must balance current revenues from one source against current revenues from other sources and future revenues. The State must also consider environmental damage, and the direct economic effects of oil activity, as well as the broader spillover impacts and balance these against the economic and social impacts of public sector activities.

These tradeoffs naturally lead to the question, how have production and drilling activities been affected by the various tax structures in Alaska? A robust assessment of this question using causal inference techniques is outside the scope of this analysis. Instead, we provide some descriptive statistics and highlight broad patterns which are useful to inform the basis of more rigorous future analysis.

Figure 4 shows Alaska oil production both in levels and as a fraction of total US oil production over the period 1980-2020 and the four tax regimes over that period. If Alaska has a generally competitive tax environment, we might expect higher levels of production in the state relative to the US. Conversely, when the tax structure is unfavorable, production might fall relative to the rest of the country. The price of oil is relevant when considering absolute production levels, but because oil prices are generally determined on a global market, the price of oil has little impact on the relative production levels in the lower panel.

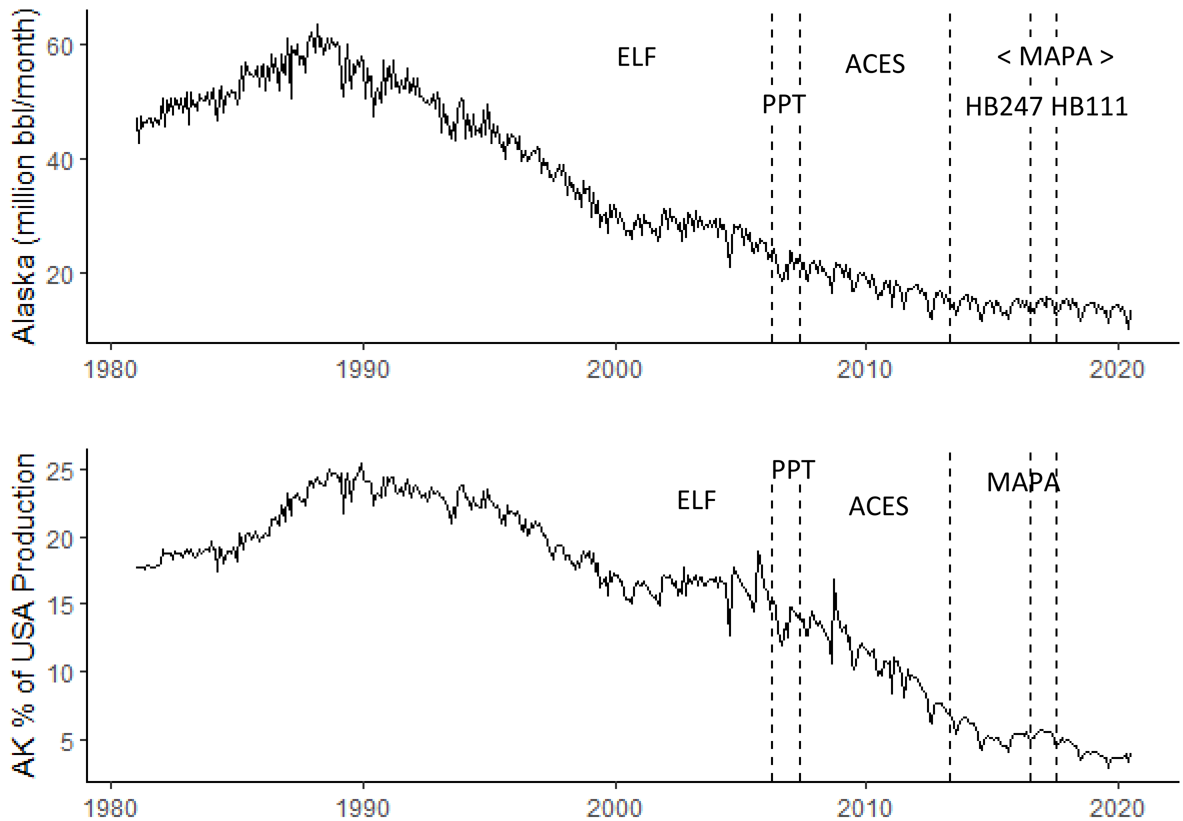
Since the early 1990's, production in Alaska has been declining in absolute terms and relative to the nation. Under ELF between 1990 and the signing of PPT, Alaska produced an average of 38 million barrels per month and production declined an average of 176 thousand barrels per month, or about 0.47% month-over-month. Under PPT, production averaged 22 million per month, declining an average of 133 thousand barrels per month or 0.59%. Under ACES, production averaged 18 million barrels per month, declining an average of 112 thousand barrels per month or 0.59%. Under MAPA, production averaged 14 million barrels per month, declining 24 thousand barrels per month, or 0.17%.

These trends are roughly similar when compared to the nation in the lower panel of Figure 4. Under ELF, Alaska as a percent of US monthly production averaged 0.05 percentage points (pp) less than the previous month, 0.1pp under PPT, 0.1pp under ACES, and 0.03pp under MAPA.

Reimer et al., (2017) uses more rigorous empirical methods to test whether the high taxes rates in the ACES regime had a negative effect on production, drilling, employment, and state GDP. Their analysis finds no evidence of negative effects on these outcomes. This inconclusive evidence is the only academic, peer reviewed, and Alaska-specific analysis to date of the impact of differing oil tax regimes.

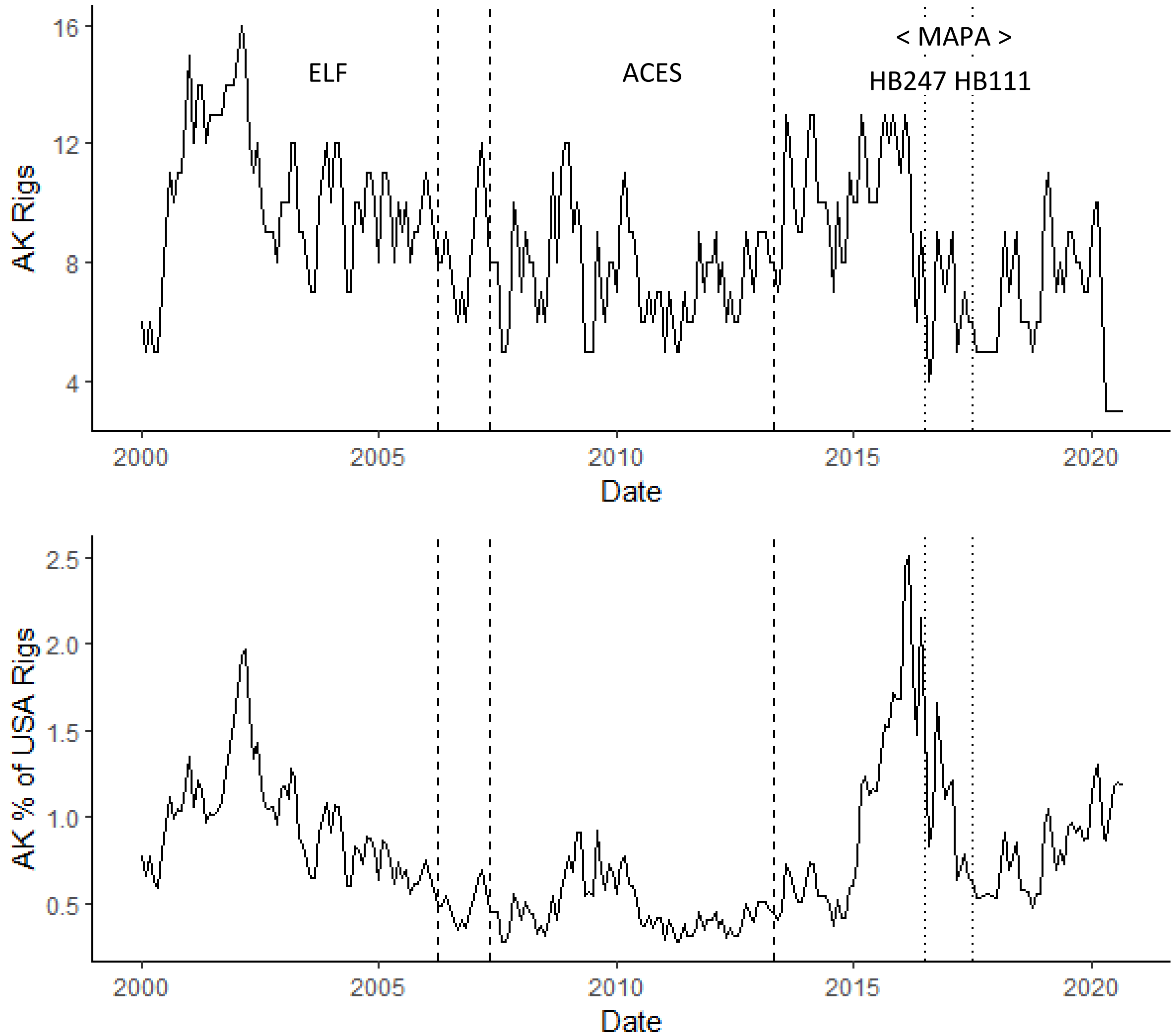
Figure 5 presents the count of the number of oil rigs operating in Alaska averaged over each month from January 2000 to August 2020. Rigs are reflective of exploration and development activity and serves as one measure of investment activity. The top panel of Figure 5 shows the total average rig count while the lower panel show the rigs operating in Alaska as a fraction of the rigs operating throughout the U.S. Under ELF, Alaska average 10.3 rigs per month, 8.4 under PPT, 7.6 under ACES and 8.2 under MAPA. Alaska accounted for 0.97%, 0.49%, 0.47%, 0.93% of US Rigs under these ELF, PPT, ACES, and MAPA, respectively.

Figure 4: Monthly Alaska Oil Production and % of US Oil Production, Jan 1980-July 2020



Source: Author's figure based on Energy Information Administration, Petroleum Supply Monthly Report. Top panel, Alaska production in million bbl/month. Bottom panel, fraction of US production from Alaska. Overlaid are the dates each of the production tax regimes were singed into law. HB247 and HB111 were reductions or eliminations of cashable credit programs.

Figure 5: Monthly Alaska Oil Rig Count and % of US Rig Count, Jan 2000-Aug 2020

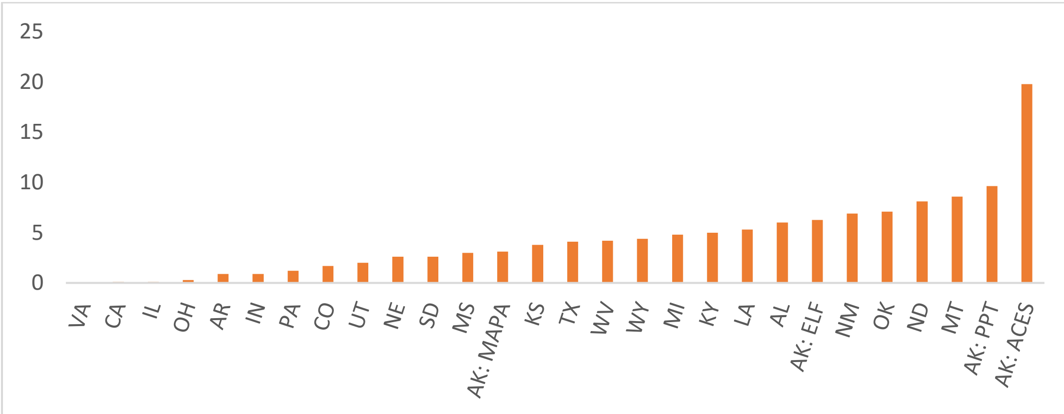


Source: Author's figure based on data from Baker Hughes. Top panel is the average rig count operating in Alaska in a given month. Lower panel are the fraction of US rigs operating in Alaska. Overlaid are the dates each of the production tax regimes were singed into law. HB247 and HB111 were reductions or eliminations of cashable credit programs.

Comparison of Oil Severance Taxes Across States

Figure 6 compares the average effective production tax rates actually experienced under Alaska's four oil tax regimes during the relevant years to the effective severance tax rates experienced by other U.S. states over the period 2004-2013. Estimates from other states come from Weber et al. (2016) and are limited to the years assessed by their analysis. Under the market conditions that existed at the time they were in effect and tax structure of ACES and PPT, Alaska had higher effective tax rates than other states during the 2004-2013 period. Under MAPA, effective tax rates are lower in comparison toto many other states for 2004-2013. However, this comparison must be interpreted with great caution because prices fell very significantly after 2014 and the data for the other states ended in 2013.

Figure 6: Effective Severance Tax Rates (%) by State and Tax Regime



Source: Effective tax rates for non-Alaska states comes from Weber et al. (2016). Non-Alaska state rates are estimated for the years 2004-2013. Alaska effective production tax rates are calculated using data from 2018 Fall Revenue Sourcebook from Alaska DOR. Alaska's effective production tax rate is calculated as the actual total production taxes collected divided by the gross value of oil produced. ELF was in place 1970-2006, PPT 2006-2007, ACES 2008-2013, MAPA 2013-2018.

Using the tax models for MAPA and Ballot Measure 1 developed for this report, we can look retrospectively over the past 40 years to compare how these two tax regimes would have performed had they been in place, compare them the actual effective tax rates seen in Alaska, and actual effective rates in other states over this period, in a more consistent fashion. Table 1 below presents effective tax rates in other states over the period 1981-2015 as estimated by Brown, Maniloff, and Manning (2020), and the actual and hypothetical Alaskan rates over the same period. For the hypothetical Alaskan taxes, actual prices from 1981-2015 are used, but all other parameters are fixed at their FY2021 levels. This assumption is because of limited data for parameters like lease expenditures over this timeframe.

Table 1 shows that the actual effective severance tax rate in Alaska was the 3rd highest nationally from the period 1981-2015, measured in either $/bbl or % terms, just behind North Dakota and Louisiana. Had MAPA been in effect since 1981, Alaska would have ranked near the bottom in state severance taxes as a percent of gross value, and just above Texas in $/bbl terms. Ballot Measure 1 would have made Alaska the third or fourth highest severance tax state had it been in effect over this same period, with estimated effective rates just below Alaska's actual rates over that period.

Note these comparisons are narrowly focused on effective severance tax rates. They do not include other applicable jurisdiction-specific royalties, taxes, or fees. The metric that is ultimately determinative from the standpoint of jurisdictional competitiveness is the rate of return on dollars invested.

Table 1: Effective Severance Tax Rates, 1981-2015

State (Regime)	Rate (%)	$/bbl	State (Regime)	Rate (%)	$/bbl
MO	0	0	AR	5.1	2.76
PA	0	0	WY	6	3.27
OH	0.1	0.03	KS	6.5	3.29
NE	4	2.18	NM	7	3.78
KY	4.5	2.44	OK	7.1	3.84
TX	4.6	2.5	MT	8.8	5.23
AK: MAPA	2.99	2.64	AK: BM1	8.28	5.32
CO	5	2.71	AK: Actual	9.87	5.35
WV	5	2.71	ND	11.4	6.21
UT	5.5	2.73	LA	12.5	6.78

Source: Alaska amounts come from author's calculations. Other data come from Brown, Maniloff, and Manning (2020). Rates from other states, and 'AK: Actual' are the actual effective severance tax rates from 1981-2015. These rates span tax regimes, oil prices, and other factors. AK: MAPA and AK: BM1 use the tax model developed in this report to estimate the effective tax rate had these two regimes hypothetically been in place from 1981-2015, given the observed prices over this period, but holding all other parameters fixed at their 2021 levels.

III. Potential Impacts of Ballot Measure 1

The impacts of BM1 can be thought of in two ways. First, how much revenue might the state raise in the next few years, assuming producers do not change their behavior from the status quo. Second, recognizing that firms are in fact likely to change behavior, what are the implications for oil production and investment, employment and wages in oil and related industries, and short and long run state revenue? How might the different components of BM1 influence these behaviors?

BM1's ringfencing provisions may also have import implications for both the short run revenue raised, producer behavior and in turn other long run changes. Because of data limitation, we will only provide a crude estimate of the short run revenue implications for the ringfencing provisions.

III.A. Potential Impact on State Revenues

Potential Revenue: Static, Single Year Effects

This analysis considers the incremental revenue from BM1 relative to the status quo. We assuming no behavioral change from the tax increase and no effect from ringfencing, so the only revenue changes will be revenue increases from increasing tax rates in the 40/400 areas, which DOR's Fall 2019 forecasts to produce 147 million barrels in 2021.

To construct this comparison, we develop a simplified model of tax revenues under the current SB21 structure and the proposed structure of BM1. This model replicates the "Order of Operations" tables that are constructed by the Alaska DOR. This model is described in detail as part of the *Technical Appendix: A model of taxes under SB21 and BM1*.

A few important assumptions worth noting here. First, this analysis focuses on the production in the 40/400 areas, as we are trying to primarily understand the incremental revenue effects of BM1. So, while the AK DOR projects 179 million barrels of production statewide in FY21, this analysis focuses on the 147 million barrels projected to come from the 40/400 areas. However, given certain economic data in the "Order of Operations" does not distinguish between the 40/400 areas and the rest of the state, this analysis also assumes that the average statewide values for average lease costs and other important values are good approximations for those specific to the 40/400 areas. In reality, average lease costs are likely lower in the 40/400 areas, but we lack sufficient data to quantify this nuance. Instead, we conduct sensitivity analysis across many possible lease costs.

Table 2 shows the total revenue in the 40/400 areas in the status quo case and under BM1 and incremental revenue from BM1 under various prices and three lease costs scenarios. We consider as the base case an oil price of $40/bbl (close to the AK DOR Spring 2020 forecast for the next several years) and an average lease cost of $30/taxable barrel of oil, rounded from the $29.02/tax barrel used in the Fall 2019 forecast for FY21.

Alaska DOR forecasts modest increases in oil prices over the next decade, rising from $40/bbl to $53/bbl in 2029. At current lease costs, these prices would translate to $238m and $397m in additional revenue under BM1. Prior to the outbreak of COVID-19 and the resulting collapse in global oil demand and prices, AKDOR's Fall 2019 forecast projected the highest ANS price at $71/bbl in 2029. At these prices (and at a $30 average lease cost), incremental revenue from BM1 would be $1,049m.

Figure 7 is expands on the data from Table 2 by providing a graphical presentation that encompasses the entire range of combinations of prices and lease costs. The each color band represents a range of the potential incremental revenue from BM1 given various prices and least costs. For reference, there are points in Figure 7 that identify the prices and lease costs realized in given years 2015 to 2021. To pick one point in Figure 7, under conditions in the Spring 2020 forecast for FY2021, prices of $37/bbl and lease costs of $29/taxbbl, BM1 would raise $357m under BM1 as compared to the status quo revenue of $143m. This results in for an incremental effect of $214m.

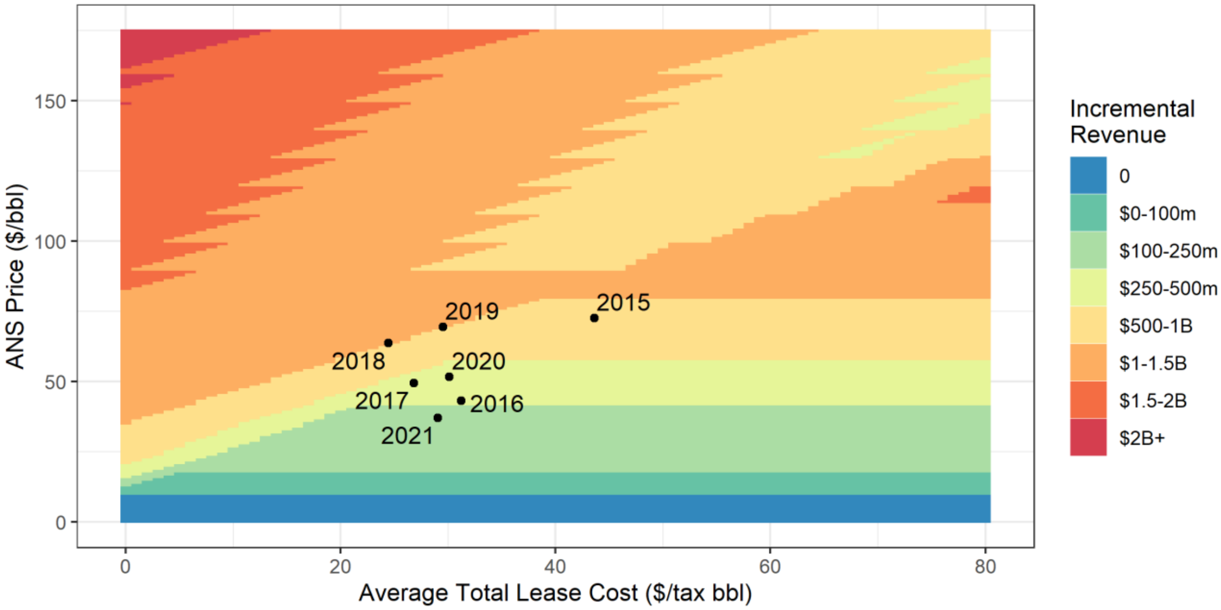
At least two results emerge from Figure 7. First, our recent experience from 2016 to 2021 is in a region of prices and costs where the net increase BM1 would have been sensitive to prices. The increase under 2021 prices and costs would be about $200 million, while the increase would be about $1 billion at 2019 prices and costs. And even a $20 increase in price would push the revenue effect of BM1 to $1.5 billion. Second, there are few combinations of prices and costs that result in more than $1 billion of increased revenues under SB 21. Those occur at prices of $100/bbl and relatively low costs. An important feature of Figure 7 is that only under the most extreme oil price or lease costs scenarios does the incremental static revenue from BM1 exceed $1.5B.

Table 2: Static Effect of BM1 On Rates and Revenue, No Ringfencing or Monthly Effects

		Current: MAPA/SB21			Proposed: BM1			BM1-MAPA		
Lease Cost/ tax bbl	ANS Price $/bbl	40/400 Revenue $m	Rate %	$ /bbl	40/400 Revenue $m	Rate %	$/ bbl	Revenue $m	Rate %-%	$/ bbl
15	35	132	2.6	0.90	446	8.6	3.03	314	6.1	2.1
	40	159	2.7	1.08	671	11.4	4.55	512	8.7	3.5
	45	185	2.8	1.25	896	13.5	6.08	711	10.7	4.8
	55	297	3.7	2.01	1,346	16.6	9.13	1,049	12.9	7.1
	65	746	7.8	5.06	1,796	18.7	12.18	1,049	11.0	7.1
	75	1,196	10.8	8.12	2,250	20.4	15.27	1,054	9.5	7.1
	85	1,646	13.1	11.17	2,897	23.1	19.65	1,250	10.0	8.5
	95	2,227	15.9	15.11	3,543	25.3	24.04	1,316	9.4	8.9
	105	2,809	18.1	19.06	4,190	27.1	28.43	1,382	8.9	9.4
30	35	132	2.6	0.90	331	6.4	2.24	198	3.8	1.3
Base Case	**40**	**159**	**2.7**	**1.08**	**396**	**6.7**	**2.69**	**238**	**4.0**	**1.6**
	45	185	2.8	1.25	462	7.0	3.13	277	4.2	1.9
	55	237	2.9	1.61	657	8.1	4.46	420	5.2	2.8
	65	290	3.0	1.97	1,107	11.6	7.51	817	8.5	5.5
	75	508	4.6	3.44	1,557	14.1	10.56	1,049	9.5	7.1
	85	958	7.6	6.50	2,007	16.0	13.62	1,049	8.4	7.1
	95	1,539	11.0	10.44	2,560	18.3	17.37	1,021	7.3	6.9
	105	2,120	13.7	14.38	3,206	20.7	21.75	1,087	7.0	7.4
45	35	132	2.6	0.90	331	6.4	2.24	198	3.8	1.3
	40	159	2.7	1.08	396	6.7	2.69	238	4.0	1.6
	45	185	2.8	1.25	462	7.0	3.13	277	4.2	1.9
	55	237	2.9	1.61	652	8.0	4.43	415	5.1	2.8
	65	290	3.0	1.97	942	9.8	6.39	652	6.8	4.4
	75	342	3.1	2.32	1,283	11.6	8.71	941	8.5	6.4
	85	395	3.2	2.68	1,480	11.8	10.04	1,085	8.7	7.4
	95	850	6.1	5.77	1,768	12.6	12.00	918	6.6	6.2
	105	1,431	9.2	9.71	2,223	14.4	15.08	791	5.1	5.4

Production 147 million bbl/year
Source: Author's Calculations using the method described in this section. Assumes production of 147 million barrels per year from the 40/400 areas. Transportation cost of 9.79/tax barrel. Effective royalty rate of 11% and effective GVR rate of 2%. Assumes only applicable credits under SB21/MAPA are sliding scale non-GVR credits. Revenue only includes production tax revenue and not revenue changes from any other source.

Figure 7: Static Incremental Revenue, No Ringfence or Monthly Effects



Source: Author's calculations of additional revenue from BM1 under static conditions. Potential effects of production changes and effects of ringfencing are not considered here. Points on the figure are actual or forecasted prices and lease costs in the denoted year. For years 2015-2018, values come from DOR's 2019 Fall Revenue Sourcebook FY2021 forecasts for ANS prices and lease costs. For years 2019-2021, values come from DOR's 2020 Spring Update.

Potential Revenue: Over a Decade

Over the next 10 years, AK DOR projects production in the 40/400 areas to continue to decline. Because Ballot Measure 1 establishes a 40k barrel per day threshold to qualify for the increased tax rates, certain fields may see natural declines in their production that disqualify them for the proposed tax increase. At the same time, AK DOR does not project any other field to exceed the 400 million cumulative barrel threshold before the end of the coming decade. As Figure 8 shows, AK DOR projects Alpine's daily production to fall below 40k barrels per day by 2026. These projections of course ignore any potential behavior change on the part of producers to the tax change.

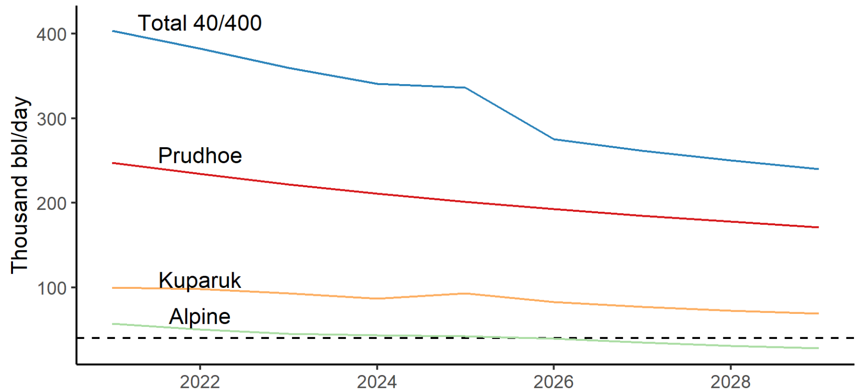
Because potential future revenues will be a function of declining production and uncertain prices, we evaluate the potential revenues of the measure over the next decade, from 2021 to 2029. We use AK DOR's forecast for the key parameter values of prices, quantitates produced, lease expenditures, transportation costs, effective royalty rates and effective GVR rates. AK DOR provides price projections under a base case as well as a high and low price scenario. We also estimate potential revenues under these alternative scenarios as well. These price scenarios vary price only, and ignore likely producer changes to the cost or quantity of production.

Because the tax model does not incorporate carry forwards on lease expenditures and because it aggregates over all producers, the average lease expenditure per barrel forecasted by AK DOR is higher than what will actually be taken as deductions. Lease costs over the forecasted period averaged $40.35/tax bbl, around $10 more per barrel than was assumed in our base case. If lease costs in the relevant fields are lower, this will have the effect of underestimating production tax revenue when prices are high enough such that the net tax would be binding. Parameter values for each year are provided along with other details in *Technical Appendix: Decade Analysis*.

Using these projected values, we compare revenue in the three areas of Prudhoe Bay, Kuparuk, and Alpine in each year under the status quo and under the rates set by Ballot Measure 1. Like the single year analysis above, this analysis does not consider the effect of monthly tax calculations, ringfencing, or the dynamic effects of producer response to the tax increase. The annual revenue collected for each year from 2021-2029 are presented in Figure 9.

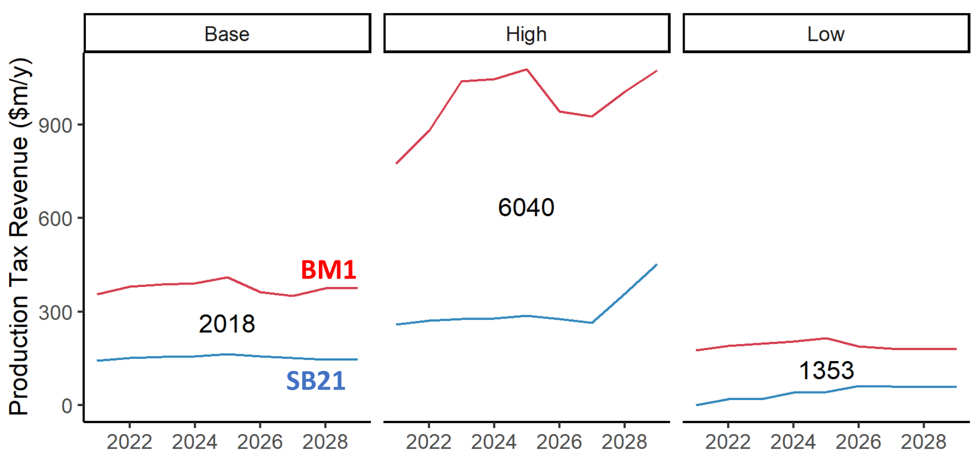
In the base case, AK DOR projects prices to rise modestly from the low $40s to the low $50s over the next decade and these increases are enough to offset production declines such that overall production tax revenue is flat both under the status quo and under the prosed Ballot Measure 1. The incremental effect of Ballot Measure 1 over the nine years is $2,018 million in additional production tax revenue. Averaged annually ($224 million per year), this is not wildly different than the $239 million per year estimated in the one-year-ahead base case. Higher prices and lower lease costs offset the declines in production. In the high price case, incremental revenues through the decade are a much higher $6 billion, while in the low price case, they are only a slightly more modest $1.3 billion.

Figure 8: Daily Production Forecast for 40/400 Fields, 2021-2019



Source: Author’s calculation from AK DOR 2019 Fall Revenue Sourcebook. Kuparuk and Prudhoe include their respective satellite fields. Total 40/400 is the sum of fields meeting the 40,000 barrels per day threshold.

Figure 9: Annual Total and Cumulative Incremental Production Tax Revenue, 2021-2019



Source: Author’s calculation. Production tax revenue from BM1 and SB21 under AK DOR’s Spring base case, low and high price forecasts. Cumulative incremental revenue from BM1 from 2021-2029 is presented between the curves.

Potential Revenue: What effect will the monthly tax calculation have?

To understand the effects of the monthly tax calculation, we calibrate our static model using parameter values for the years 2015-2020 from the Fall 2019 Revenue Sourcebook. Daily price data are from Alaska DOR Prevailing Values, ANS West Coast Average Spot Price. These; these data are aggregated to the monthly level.

Assuming all other parameters but prices remain fixed over the course of the year, we calculate the production tax liability for the proposed BM1 structure for each month given the average monthly spot price.

The inputs and results of a monthly calculation of taxes are presented in Table 3. The rightmost column shows the additional revenue resulting from the monthly calculation above and beyond the tax rate changes in BM1. As shown, the monthly calculation captures an additional $0-53m dollars per year.

Table 3: Impacts of Monthly Tax Calculations

								Revenue Under BM1		
Year	Avg. Price	St.dev. P	q	ct	cl	r	gvr	Yearly	Monthly	Difference
2015	52	8	15	10	44	0	0	741	754	13
2016	43	7	16	10	31	0	0	544	550	6
2017	54	5	16	10	27	0	0	1016	1017	1
2018	71	6	16	10	24	0	0	2148	2148	0
2019	65	3	15	8	30	0	0	1530	1530	0
2020	41	13	15	9	30	0	0	417	470	53

Source: Author's calculations. Q (millions of barrels per month), ct, cl, r, gvr based on data from the Fall 2019 Revenue Sourcebook. Alaska DOR Prevailing Values ANS West Coast Average Spot Price. Avg p is the average price for a given year, st.dev p is the standard deviation of prices for the 12 months in a given year.

Potential Revenue: What if Taxes Cause Production Decline to Accelerate?

AK DOR's Fall forecast projects production to decline in the 40/400 areas from about 147 million barrels per year in 2021 to 88 million barrels per year in 2029, for a simple average year-over-year decline of about 4.5%. If Ballot Measure 1 curtails investment in new wells (or sustaining capital and operating cost for current wells), this projected rate of decline is likely to accelerate. Production declines due to the tax increase will offset some of the incremental revenue.

To understand potential production declines, one approach would be to make a before-the-fact guess at how much firms are likely to respond to the tax. There is some existing evidence from the academic economics literature on the subject, but it would be difficult to make the argument that those estimates apply perfectly in this case. Instead, this analysis will ask how much would production declines need to accelerate to completely offset the revenue from the increased tax rate? Phrased differently, how much would the world have to change in order for Ballot Measure 1 to not only be a wash from the status quo, but to actually reduce total State revenue over the next decade.

We estimate the production decline when BM1 would "breakeven" with the status quo. For this analysis, we consider only revenue from royalties and production taxes. We assume that the effects from BM1 are confined to the currently defined 40/400 areas (Prudhoe Bay, Kuparuk and Alpine). We also assume that average lease expenditures remained fixed at DOR's forecasted statewide level (this assumption is relaxed in the next section). We discuss the implications of these assumptions in more detail in *Technical Appendix: Decade Analysis*.

In every year, and at each given rate of decline, the model determines whether a particular field meets the 40,000 barrel per day threshold required for a field to be subject to the BM1 tax. In DOR's status quo scenario, Alpine will not be subject to BM1 after 2025. As the production rates of decline increase under our alternative scenarios, this date is shifted forward. At sufficient production decline scenarios (if decline were to accelerate 6 percentage points, from 4.26% per year to 10.26%), Kuparuk also becomes in-eligible for the BM1 tax within the 2021-2029 timeframe.

We model the potential decrease in investment because of the tax as an acceleration of projected decline. AK DOR projects that production will decline on average 4.5% per year in the 40/400 fields from 2021-2029. As shown in Table 4, individual fields are projected to decline at a slightly different rates under the status quo. If the proposal causes production to decline faster than the status quo, this will negatively impact both the production tax revenue and the royalty revenue raised from these fields. By increasing the rate at which these fields are declining, we determine the decline necessary for BM1 to breakeven in production tax and royalty revenue with the status quo.

If prices follow the trajectory in DOR's 2020 Spring base case, Ballot Measure 1 would need accelerate average production declines by 4.75 percentage points in each of the three fields. Current average decline in the three fields is 4.5%, meaning that the average decline rate would need to more than double to 9.25% for it to raise less revenue through 2029 than in the status quo case.

If prices follow the trajectory in DOR's low case, production declines would need to accelerate by 5.75 percentage points up to 10.25% per year to break even. In the high price scenario, Ballot Measure 1 would need to accelerate declining production by 7.25 percentage points to 11.75% per year in order to breakeven or do worse than the status quo. This required decline is 2.5 times faster than what DOR currently projects.

Table 4: Production Declines Required For BM1 to Breakeven 2021-2019

	Average Decline in Status Quo (%/year)	Decline Rates Required to Breakeven: Acceleration (pp/year)			Total (%/year)		
		Base	Low	High	Base	Low	High
Prudhoe	4.04	4.75	5.75	7.25	8.79	9.79	11.29
Kuparuk	4.26				9.01	10.01	11.51
Alpine	4.92				9.67	10.67	12.17
Total 40/400	4.5				9.25	10.25	11.75

Source: Author's calculations. Average decline in status quo is the current simple annual average year-over-year percent decline in production by field and total over the 40/400 area as projected by AK DOR Fall Revenue Sourcebook from 2021:2029. Acceleration is the percentage point increase in the average decline rate in the status quo scenario required for Ballot Measure 1 to breakeven in state royalty and production tax revenue, or do worse. Total %/y is status quo decline plus the required acceleration in decline required for BM1 to breakeven.

Potential Revenue: Investment to Falls & Production Declines Accelerate

The previous section considered a scenario where production declines accelerate at different rates, but assumed all other factors stayed fixed at their DOR-projected levels. Of course declining production would be caused by curtailed investment activity, so assuming capital and operating expenditures are fixed at their projected levels while production declines is unrealistic. This is important because capital and operating expense deductions reduce tax liability toward the minimum tax floor; low expenses (all else equal) results in more tax revenue for the State.

This section seeks to understand how reduced expenditures and accelerated production declines will jointly affect the overall tax revenue generated. While there is some empirical relationship between capital and operating expenses and decline acceleration, estimating this is outside the scope of this report. Instead, we present a range of scenarios of expenditure reductions and decline acceleration rates.

The decline acceleration rate scenarios include values between 0 to 35 percentage points of additional production decline per year. As in the previous section, these values are added to the projected average annual decline for each of the 40/400 fields, which is projected to be about 4.5% per year averaged across the 40/400 units. In the most aggressive scenario, production declines at a rate of 35 + 4.5 =39.5% per year, and production in the 40/400 areas ceases by 2024.

The lease costs scenarios are equally simplistic. They reduce by between 0 and 100% the statewide deductible operating and capital lease expenditures relative to their DOR projected levels. The most extreme scenario (100%) assumes that no lease expenditures are deducted.

This wide range of potential outcomes is quite unlikely in reality; even less likely are particular combinations. It is unrealistic to think that production decline accelerates by 35 percentage points, while lease expenditures see a 0% reduction from their projected baseline. Similarly, it is impossible that production declines would see 0 acceleration when lease expenditures are reduced 100%.

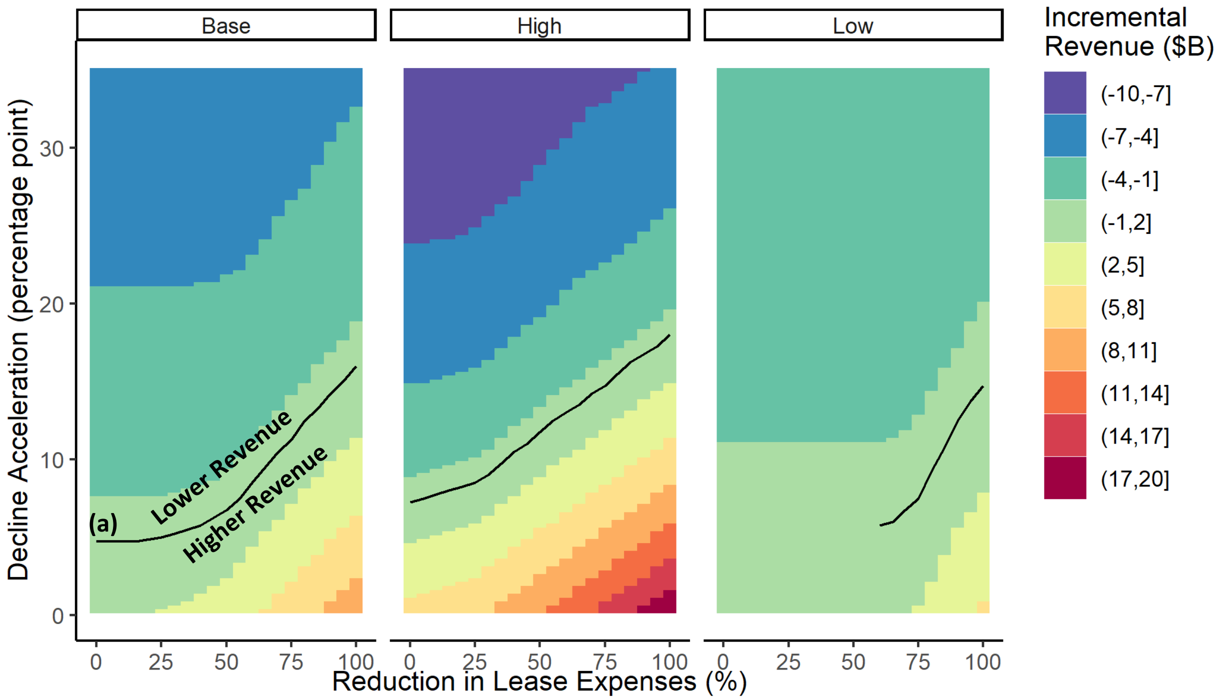
As in the previous section, we adopt AK DOR's base case, high, and low-price scenarios.

Figure 10 shows how different combinations of production decline acceleration rates and lease-cost reductions jointly affect overall State revenue from royalties and production taxes. The black line through the figure shows the point where the State "breaks even" from Ballot Measure 1. Area above or to the left of this line implies the State would have been better off in the status quo tax regime.

In the previous section, we calculated that the breakeven production decline rate for Ballot Measure 1 in the base case was approximately 9.25% per year, an increase of 4.75 percentage points over the projected rate. As the previous section assumed no reduction in lease costs, the base case from the previous section is represented in the figure as point label (a).

A take away from the base case and low price scenario figures is that lease costs would need to fall by around 50% before additional production declines could be offset. This means that the breakeven decline rate estimated in the previous section (about 9.25% and double the current rate) is valid over a large range of lease cost reductions. This invariance to lease costs is because in most years in the projected period, the minimum gross tax will apply, and this amount does not depend on lease costs. When prices rise or lease costs fall sufficiently, the net tax begins to apply in more years. This is why in the high price scenario, the breakeven decline rate is more sensitive to smaller lease costs reductions.

Figure 10: Production Declines And Lease Costs Required For BM1 to Breakeven Between 2021-2019



Source: Author's calculations. See section text for details. Incremental Revenue from BM1 cumulatively from 2021-2029. Decline acceleration are scenarios for additional decline in each of the 40/400 fields above the baseline rates. Reduction in Lease Expenses are % reduction in operations and lease expenditures in the 40/400 fields relative to the projects by AK DOR Fall 2019 Revenue Sourcebook projections. Point (a) is the base case breakeven decline estimated in the previous section, +4.75%.

40/400 Threshold

Another important impact of the proposal in the hard cutoff established by the 40/400 provisions. At current prices and lease costs, a field with an average of 40,001 barrels per month will pay nearly $2 million more in taxes in that month than a field production 39,999 barrels. This creates two important incentives. At enactment of the proposal, the geographic scope of each field will need to be determined. Firms will argue for delineations that create many small fields; proponents will argue for a smaller number of large fields. Second, going into the future, as production in certain fields declines to near this threshold (or when emerging fields approach it for the first time), there will be a strong incentive to curtail production below the threshold.

Ringfencing

Ringfencing is designed to limit deductions taken against a producer's net tax liability as its reduced toward the minimum tax floor. In this way, ringfencing is only consequential when a ringfenced field is subject to the net tax rather than the minimum tax. If prices and lease costs are such that the producer is already paying the minimum tax for a would-be-ringfenced field, the incremental effect of ringfencing is zero, regardless of activities outside the ringfence. Ringfencing has ***potential*** to play a role when the net tax is applicable, i.e. a high price/ low Legacy-field-expense environment. However, if a firm is facing the prospect of a net tax liability outside the 40/400 areas and wellhead prices are below $50/bbl, it makes no difference if the marginal lease expenditure is ringfenced or not. At wellhead prices above $50/bbl, the additional 15% marginal tax rate means that a dollar deducted in the 40/400 areas is more valuable than a dollar deducted in the non-40/400 area when both areas are facing net taxes.

We consider the effects of ringfencing retrospectively (the hypothetical effect of ringfencing had BM1 in in effect in the past) and the effects of ringfencing prospectively, (what effect it might have going forward should BM1 pass).

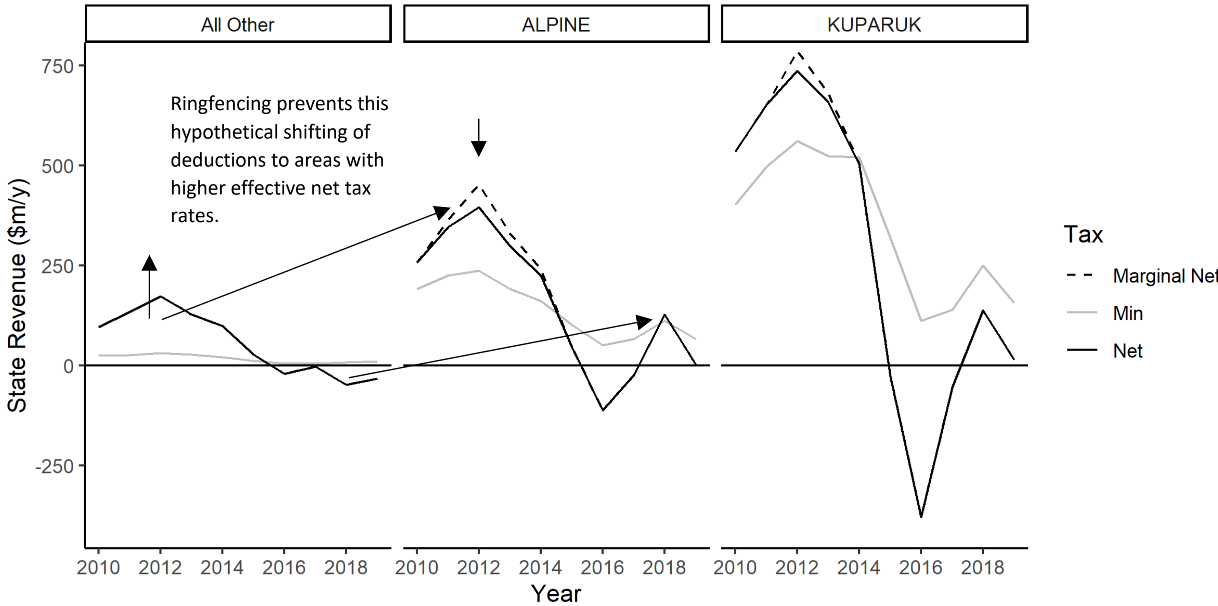
Retrospectively

Since Conoco's 2000 acquisition of ARCO, there have only been three players operating in the 40/400 areas of the North Slope: BP Alaska, ConocoPhillips, and with its recent acquisition of Prudhoe Bay, Hilcorp. Over this timeframe, BP Alaska only operated in Prudhoe Bay, meaning there would have been no potential incremental revenue gains for the State from ringfencing Prudhoe Bay before the sale of BP Alaska. ConocoPhillips, on the other hand, does have operations inside and outside the current 40/400 areas.

Using DOR and Alaska Oil and Gas Conservation Commission (AKOGCC) we can estimate the hypothetical tax liability for ConocoPhillips between 2010 and 2019. For this analysis, we use DOR's Fall 2019 Revenue Sourcebook reports of allowable capital and operating lease expenditures for the North Slope and Rest of Alaska areas. We then allocate these costs to individual firm-fields using a simple rule. We allocate operating costs by barrel produced and capital costs by feet of wells drilled. Of course per-unit operating and capital costs are likely to vary substantially across firms and fields, but there is no publicly availability data to capture this detail.

Figure 11 shows the hypothetical tax liability from 2010 to 2019 for ConocoPhillips in the Alpine, Kuparuk and all other fields had Ballot Measure 1 been in place over this period. It shows the calculated minimum tax, the net tax, and the additional marginal net tax when wellhead prices exceed $50. Between 2010 and 2014, ConocoPhillips would have faced the additional marginal net tax in Alpine and Kuparuk. The cumulative tax liability created by the additional marginal tax from 2010 to 2014 in these fields would have been just under $200 million. This is because ringfencing would have prevented shifting lease expenses incurred in their other fields into the 40/400 fields. However, the additional revenue to the State from ringfencing is limited, even in this situation. Once sufficient deductions have been taken such that the effective tax rates between the 40/400 fields and all other fields have been equalized, there is no further incentive to shift deductions between fields. From 2010 to 2014, other fields would have also faced the 35% net tax environment. Alpine might have also faced the net tax in 2018. Because all other fields would face the minimum tax liability, ringfencing would prohibit ConocoPhillips from decreasing its tax liability by shifting expenses from other fields into Alpine until the minimum tax floor was hit. The amount of additional state revenue due to ringfencing in 2018 would have been around $15 million.

Figure 11: Hypothetical BM1 Tax Liability for ConocoPhillips by Field, 2010-2019



Source: Author's calculations based on data from AK DOR Fall 2019 Revenue Sourcebook and AKOGCC. Lines are the hypothetical tax liability from 2010 to 2019 for ConocoPhillips in the Alpine, Kuparuk and all other fields had Ballot Measure 1 been in place over this period. Producer pays the higher of the calculated minimum tax, the net tax, or the additional marginal net tax when wellhead prices exceed $50.

Prospectively

Going forward, ringfencing may have more of an impact on Hilcorp and ConocoPhillips, given both companies have a large projected presence outside the 40/400 areas. Any estimates of the prospective effects of ringfencing upon total State revenues based upon available public data are subject to serious limitations. The effects of ringfencing on state revenues cannot be accurately assessed by looking only at the legacy fields. Because ringfencing will cause firms to claim costs not allowable within the ringfenced legacy fields against non-legacy fields, we would need to know the potential to claim those costs outside the non-legacy fields. Of the North Slope production, 20% is already in non-legacy fields so there is significant opportunity to claim costs in non-legacy fields. Moreover, non-legacy production is projected to increase very significantly over the next decade, from an estimated 85,000 bbl/day in 2021 to 225,000 bbl/day in 2029. As non-legacy production ramps up, the impact of ringfencing will decline.

Because of the inherent limitations in any quantitative estimates, instead, this section will describes the qualitative features of three important potential impacts.[1] The effect of ringfencing on state revenue, firm profits, and the relative risk shared between the state and firms.

Oil producers must typically spend a large amount of money on exploration and drilling up front and for many years before a single barrel of oil is produced or a single dollar is earned. Under the current SB21 framework, companies may claim deductions on qualifying expenditures in one field against their revenues from any fields in the State that are already producing.

[1] Proponents of Ballot Measure 1 have cited the a recent DOR report that $300 million per year in deductions might be claimed because of investment in the NPR-A area, but we have not attempted to verify this estimate.

The ringfencing provision prevents deducting the up-front expenses to develop a field outside the 40/400 area against the tax on net income for fields inside 40/400 areas. Instead, firms will have to wait and carry-forward these expenditures until they have revenues on their non-40/400 fields to claim the expenses against.

Putting aside the effects of risk, ringfencing will shift dollars over time. Instead of claiming deductions for investment this year, companies will carry these forward for several years before eventually claiming them. What may provide some additional revenue for the state today will amount to equivalent foregone revenue in the future.

Of course the principle of the time-value of money is relevant when considering the timing of incoming and outgoing dollars. Money in the future is worth less than money today because of missed investment opportunity in the present. For the State such investment includes tangible financial investments that provide monetary returns (e.g. the Permanent Fund) and more abstract investments such as education and infrastructure. For firms, foregone investments are oil fields left undeveloped or financial investments not purchased.

Perhaps the most important issue in considering the impact of ringfencing is the issue of how risk is shared between firms and the State. Currently, a firm may earn sufficient income in the 40/400 area to fully deduct the expenses from a new project outside the 40/400 area. If the project is unsuccessful and never becomes operational, from the state's perspective the foregone revenues from the deductions have 'bought nothing'. Ringfencing shifts more risk from the state to firms. Given the current patterns of exploration on the North Slope, it is likely that under ringfencing, firms will be able to only claim the deductions on successful projects sometime in the future. And they will incur high costs if projects are unsuccessful. As noted above, increased production in the non-40/400 areas may make this provision non-binding.

III.B. Evidence from Resource Economics Literature

Taxes, Production, and Drilling

How might BM1 impact employment in the oil sector and in upstream/downstream industries in Alaska? First, we must consider the impact of the tax on production and drilling. For production, the evidence (including past analysis conducted for ACES in Alaska) generally shows production reductions in response to tax increases are small (Rao, 2015; Reimer et al., 2017; Bjørnland et al., 2017). Anderson et al. (2018) provides theoretical and empirical explanations to these small responses, arguing that short run production is unresponsive because the relevant decision margin is the timing of drilling a well (which creates a flow of future production).

Several studies have estimated the change in drilling activity with respect to a change in oil prices. These include Anderson et al. (2018), Newell et al., (2016), and Newell and Prest, (2017) which have generally found that for a 1% change in oil price, the change in oil drilling activity is <1% (i.e. drilling is price inelastic). But Brown, Maniloff, and Manning (2020) argue firms will respond differently to changes in global prices to changes in local taxes.

Brown, Maniloff, and Manning (2020) estimates the responsiveness of drilling activity to changes in severance taxes in the same state. They compare drilling activity a given oil field that stretches across the border between two states and compares drilling on each side when taxes change in one state. This complicates extrapolating their estimate to the context of BM1, as no oil field effected by the measure extends into another state's jurisdiction. In communication with the authors, they suggest their estimates may be interpreted as an upper bound for the effect of the tax increase in Alaska.

With these important limitations noted, Brown, Maniloff, and Manning (2020)'s main specification estimates that a $1 increase in severance taxes per barrel decrease the number of wells drilled annually by 8%. Under prices of $40 per barrel and lease costs of $30 per tax barrel, BM1 would increase severance taxes by $1.60 per barrel, implying a 12.8% decrease in annual wells drilled.

Drilling and Jobs

The energy economics literature provides some estimates for the direct, indirect, and induced jobs impacts of changes in drilling in terms of both rigs and active wells. Agerton et al. (2015) finds an additional rig provides 37 short term and 224 long run jobs across the U.S. Brown (2015) finds an additional rig provides 28 short term regional jobs and 171 long term jobs. Parades et al. (2015) finds that for each active shale-well in Pennsylvania, 6-16 jobs are supported locally. Lee (2015) finds that each oil well in Texas provided two jobs.

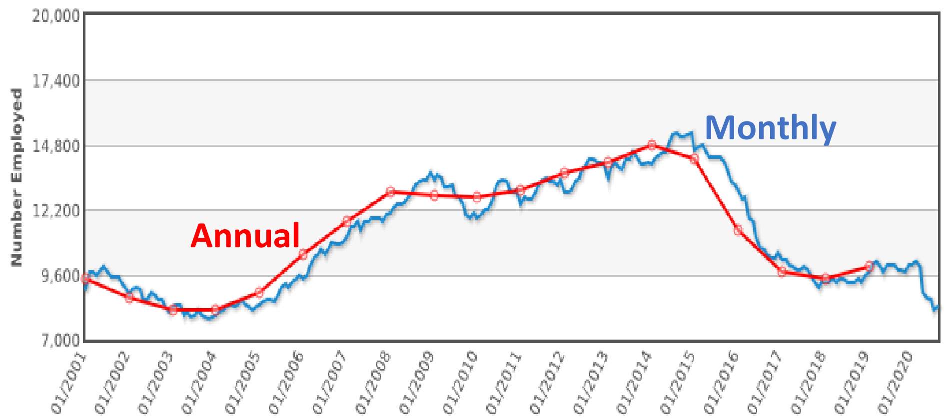
As McDowell Group (2017) notes, a large portion of the Alaska economy is supported by public sector spending from oil revenues. The job reductions in oil and related sectors must be weighed against the economic impacts of negative economic impacts of spending cuts.

III.C. Role of the Oil Industry in Alaska's Economy

While an economic impact analysis is outside the scope of this paper, it is important to provide some context to these potential impacts given the sizable role the oil and gas industry plays in Alaska's economy. This section summarizes some recent trends and analysis from others.

Over the last few years, there have been roughly 10,000 direct employees of the industry, though that has slipped recently because of the coronavirus pandemic, and is roughly 5,000 fewer than where employment peaked in late 2014. Industry employment contracted sharply after the oil price drop in late 2014. Despite the modest price increases since 2016 (and prior to the 2020 pandemic), employment has remained largely flat.

Figure 12: Alaska Oil and Gas Industry Employment



Source: Alaska Department of Labor, Research and Analysis.

The impacts of the industry go beyond the 10,000 or so jobs classified as oil and gas industry jobs. According to estimates from McDowell Group (2017), the oil and gas industry in Alaska supported 45,600 direct and spillover jobs in 2017. Accounting for the role of the industry to state and local government finance, 58,300 are attributable to the royalty and tax income the industry provides. In total, McDowell estimates around 103,900 jobs, nearly a third of Alaska's workforce, are in jobs that are supported in some way by the industry.

McDowell Group (2017) provides some comparable numbers in other industries (though with some methodological differences in their calculations). Seafood provides 41,200 full time direct and indirect and induced jobs, tourism supports 39,700, and mining supports 8,600.

IV. Uncertainty

Uncertainty in Fiscal Regime

It is important to remember the circumstances leading the BM1 proposition. Due to long-run declines in oil production and the fall in oil prices, Alaska faces a large deficit. A deficit remains despite the Percent of Market Value withdrawal from the Permeant Fund and even if no PFD is paid. Given forecasts for prices and production, the deficit will continue unless changes to revenue and spending are made.

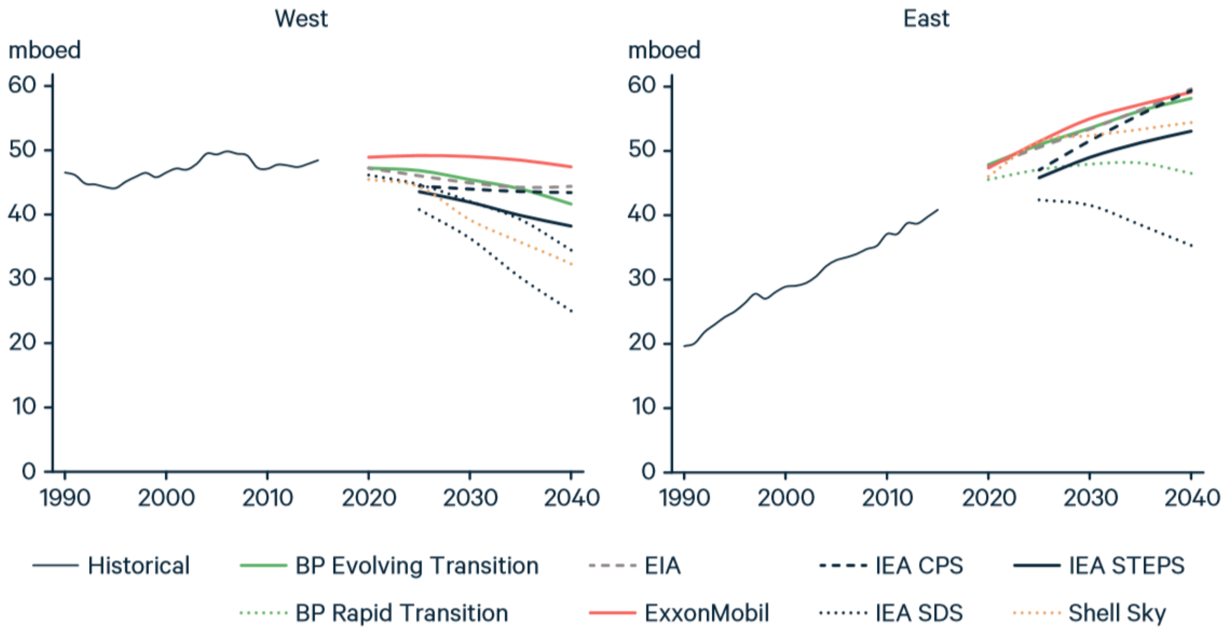
Because it is unclear what could be taxed and what could be cut, firms may be warry of making investments in the state. Business rely on services like infrastructure, public safety, and education, while also needing to make positive after-tax earnings.

Based on our estimates, Ballot Measure 1 will likely raise between $200-500 million under price and lease cost scenarios in the short run. This amount will be smaller in the long run as producers respond to the tax increase through reductions in drilling activity. It is therefore likely that spending cuts and other sources of revenue will be needed regardless of whether the measure passes. The measure may play an important role in this larger fiscal overhaul. Until a long-term sustainable plan is determined, the uncertainty created for investment by the state's fiscal situation will persist.

Uncertainty in the Future of Oil Markets

In considering the role of the oil industry in Alaska over the next 10 to 20 years, it is important to consider the global outlook for oil demand over this timeframe. Figure 10 presents a figure from Newell et al. (2020) that summarizes a number of scenarios from major institutions and energy firms. Generally speaking, there is consensus among these organization (and a range of policy scenarios) that demand for oil in the Western world is likely to fall over the coming decade due to innovations in vehicle fuel efficiency, changes in electricity generation mix, future electric vehicle penetration, public transit expansions, and public policy. In the global East, the consensus view is that oil demand will continue to climb, particularly as living standards improve in China and India. The net effect globally between now and 2040 are a range of potential estimates across these projections, ranging from -1.3% compound average annual growth to +1.1%.

Figure 13: Various Forecasts for Future Oil Demand



Source: Newell et al. (2020). See source for full details, units are in Million Barrels Oil Equivalent per Day. Scenarios drawn from the following sources: Historical and EIA: US Energy Information Administration. BP Evolving Transition and Rapid Transition from their Energy Outlook 2019. IEA current policy (CPS), stated policy (STEPS) and sustainable development (SDS) come from the International Energy Adjacency's corresponding outlooks in World Energy Outlook 2019. ExxonMobil from Outlook for Energy 2019. And Shell Sky from the Shell Scenarios 2018.

All of this to say, the future of the oil market is quite uncertain, and it is often difficult to anticipate the proliferation of destructive technology years in advance. The pace of photovoltaic solar penetration, for example, has far outpaced even some of the most aggressive expectations. This uncertainty should inform the state as it considers the source of its primary economic activities and sources of revenues.

V. Conclusion

At current oil prices, production, and costs, Ballot Measure 1 is likely to capture between $200-500 million in additional annual tax revenue in the near term. This compares to the approximately $1B State Budget deficit in FY21 ($2.2B had a PFD been appropriated using the statutory formula). Between 2021 and 2029, the initiative might raise an additional $2 billion given current projections of prices, production, and deductible lease costs. The measure might raise considerably more revenue if oil prices rise, or producer costs fall.

Instead, we estimate that the rate of projected declines in production would need to double for the state to collect less revenue under Ballot Measure 1 than under the current tax structure. These estimates are important given evidence from the economics literature which suggests taxes in general, and oil taxes specifically have negative impact on investment activity, but the magnitude of these impacts is difficult to extrapolate to the circumstances of this tax change.

The actual long run effects of Ballot Measure 1 will depend on several factors for which there is a great deal of uncertainty. The future demand for oil, the quantity of North Slope resources, extraction costs and taxes both in Alaska and in other oil-producing areas. The impacts of the measure also depend on how additional funds are utilized by the State. It is unlikely that Ballot Measure 1 will be the only required solution to the State's fiscal problems, but oil tax changes could play some role in a sustainable budget.

References

Agerton, M., Hartley, P., Medlock, K., and Temzelides, T. 2015. Employment impacts of upstream oil and gas investment in the United States. IMF Working Paper WP/15/28.

Anderson, Soren T., Ryan Kellogg, and Stephen W. Salant. 2018. "Hotelling Under Pressure." *Journal of Political Economy*, 126(3): 984–1026.

Bjørnland, Hilde C, Frode Martin Nordvik, and Maximilian Rohrer. 2017. "Supply Flexibility in the Shale Patch: Evidence from North Dakota." working paper, Norges Bank.

Brown, J. 2015. The response of employment to changes in oil and gas exploration and drilling. Federal Reserve Bank of Kansas City, Economic Review, 100(2), 57-81.

Brown, J. P., Maniloff, P., & Manning, D. T. 2020. Spatially variable taxation and resource extraction: The impact of state oil taxes on drilling in the US. *Journal of Environmental Economics and Management*, 103, 102354.

Czapla, Ewelina, Gray, Gordon. 2020. "Severance Taxes: A Case Study Analysis of Alaska's Ballot Measure 1". American Action Forum. https://www.americanactionforum.org/research/severance-taxes-a-case-study-analysis-of-alaskas-ballot-measure-1/

IHS Markit. 2020. "Alaska's Competitiveness in Global Oil and Gas Markets." Presented Sept 2, 2020 by: Irena Agalliu, Vice President, IHS Markit. Commonwealth North Forum. https://www.commonwealthnorth.org/events/#!event/2020/9/2/alaska-apos-s-competitiveness-in-oil-and-gas-markets

Lee, J.2015.TheregionaleconomicimpactofoilandgasextractioninTexas.Energy Policy, 87, 60-71.

McDowell Group. 2017. "The Role of the Oil and Gas Industry In Alaska's Economy." mcdowellgroup.net/wp-content/uploads/2017/09/mcdowell-group-aoga-report.pdf

Newell, Richard G, Brian C Prest, and Ashley Vissing. 2016. "Trophy hunting vs. manufacturing energy: The price-responsiveness of shale gas."Technical report, National Bureau of Economic Research.

Newell, Richard G., and Brian C. Prest. 2017. "The Unconventional Oil Supply Boom: Aggregate Price Response from Microdata." Working Paper 23973, National Bureau of Economic Research.

Parades, D., Komarek, T., and Loveridge, S. 2015. Income and employment effects of shale gas extraction windfalls: Evidence from the Marcellus region. Energy Economics, 47, 112120.

Rao, Nirupama S. 2015. "Taxes and U.S. Oil Production: Evidence from California and the Windfall Profit Tax." NYU Wagner Research Paper 2211681, New York University.

Reimer, Matthew N., Mouhcine Guettabia, and Audrey-Loraine Tanaka. 2017. "Short-run impacts of a severance tax change: Evidence from Alaska." Energy Policy, 107 448–458.

Weber, Jeremy G., Yongsheng Wang, and Maxwell Chomas. 2016. "A quantitative description of state-level taxation of oil and gas production in the continental US." Energy Policy 96: 289-301.

Newell, R, Daniel Raimi, Seth Villanueva, and Brian Prest. (2020) Global Energy Outlook 2020: Energy Transition or Energy Addition? Resources for the Future.

Technical Appendix: A model of taxes under SB21 and BM1

Model Current Taxes

The first step in calculating production tax liability under both the current structure and BM1 is determining the volume and value of taxable barrels. Taxable barrels allows companies to deduct the cost of royalties paid from their production taxes. Let q be the total annual quantity of oil (in thousand barrels per year) subject to production taxes. Let p be the ANS price of oil ($/bbl). The total gross revenue is therefore the product of quantity and price, $q*p$. If r is the effective royalty rate (fraction), then the $q*(1-r)$ is the quantity of taxable barrels and $q*p*(1-r)$ is the value of taxable barrels. The state's royalty income is $q*p*r$. (Note that the tax computations treat royalties as a reduction in taxable quantity. This is important because royalties do not reduce prices.)

Next, producers deduct the transportation cost incurred from the well through the gathering lines, through the trans-Alaska pipeline and carried by tanker ship to market in California. Let these costs be ct, which are denoted in $/taxable barrel. Deducting transportation costs from the value of taxable oil is referred to as the Gross Value at Point of Production or GVPP. GVPP = $q*(1-r)*(p-ct)$ and forms the basis for the minimum tax calculation.

The minimum tax rate is a function of the GVPP average price for oil $p-ct$,, mintax($p-ct$), The minimum tax function, mintax($p-ct$), has the following form:

p-ct	<$15	$15-17.5	$17.5-20	$20-25	$25+
mintax	0%	1%	2%	3%	4%

A producer's minimum tax liability is production net of royalties time gross value (net of transportation costs) times the minimum tax rate:

$$q*(1-r)*(p-ct)*\text{ mintax}(p-ct).$$

To calculate potential net tax liability, producers deduct from GVPP their allowable capital and operating costs that were directly incurred to produce oil. Let the average total capital and operating (lease costs) be cl, denoted in $/taxable barrel units. The result of deducting lease expenditures is called the Production Tax Value (PTV):

$$\text{PTV} = q*(1-r)*(p-ct-cl).$$

The last deduction before net tax is calculated is the gross value reduction, GVR. The GVR is an incentive program for certain new oil production. However, it amounts to a small portion of overall deductions taken, and so we will create an abstract approximation for it in this analysis. We use an "effective GVR" which is the fraction of GVPP claimed as a GVR. Let the value of the GVR deduction be $q*(1-r)*(p-ct)*gvr$, where gvr is the effective gvr rate. The effective gvr has been between 1% and 2% over the last 5 years.

Net tax is calculated $[(q*(1-r)*(p-ct-cl))-(q*(1-r)*(p-ct)*gvr)]*35\%$. The first term in brackets is the PTV, the second term is the GVR, and 35% is the tax rate on net income.

Next, producers can claim a number of credits against their net tax liability. The most important of these credits for the purpose of understanding BM1 is the per-barrel sliding scale credit for non-GVR eligible production. Our analysis will assume only these credits are relevant, given the small share of actual GVR production and the limited available information need ed to calculate the amounts for the smaller credit programs.

The value of the non-GVR per-barrel taxable credits are based on a sliding scale of the GVPP average price for oil, or p-ct. Let *cred(p-ct)* be the per-barrel tax credit

The *cred(p-ct)* schedule has the following form:

p-ct	<80	80-90	90-100	100-110	110-120	120-130	130-140	140-150	150+
cred(p-ct)	8	7	6	5	4	3	2	1	0

A producer subtracts their claimed credits against their net tax liability. The producer then pays the higher of the net tax or the minimum tax

Production Tax = higher of: {

Min Tax: *GVPP** mintax(*p-ct*) = *q*(1-r)*(p-ct)** mintax(*p-ct*)

or

Net Tax: (PTV – GVR)*35% – Credits = *[(q*(1-r)*(p-ct-cl))-(q*(1-r)*(p-ct)*gvr)]*35% - cred(p-ct)*q*(1-r)*

Model BM1 Taxes

The BM1 largely maintains the current tax structure, with the following changes to the 40/400 fields.

BMI changes the functional form of minimum tax rates. Instead of the minimum tax rate phasing in at low prices, it grows larger at higher prices. It also appears to modifies the relevant price for determining the tax rate by using from the GVPP price in SB21 to the gross (or ANS price), *p instead of the gross value net of transportation costs used in the current structure*. Therefore the minimum tax function, mintax(p), becomes:

p	<$50	$50-55	$55-60	$60-65	$65-70	70+
mintax	10%	11%	12%	13%	14%	15%

BM1 eliminates the per-barrel tax credits when calculating the net tax liability. It also adds a 15% marginal tax when average PTV per taxable barrel is greater than $50. This additional marginal net tax is calculated *q*(1-r)*(p-ct-cl-50)*15%* when *p-ct-cl-50>0.*

The net tax is:

[(q(1-r)*(p-ct-cl))-(q*(1-r)*(p-ct)*gvr)]*35%* when *p-ct-cl-50<0*

or

[(q(1-r)*(p-ct-cl))-(q*(1-r)*(p-ct)*gvr)]*35% + q*(1-r)*(p-ct-cl-50)*15%* when *p-ct-cl-50>0*

Producers then pay the higher of the minimum or the net tax.

Potential Revenue: Static Model Ignoring Ringfencing and Monthly Effects

To understand the potential revenues from only the tax rate changes (ignoring for the moment potential production changes from the tax increase, the monthly calculation of taxes, or the effects of ringfencing), we calibrate the static model with values from DOR's 2019 Fall Revenue Sourcebook FY2021 forecasts. These values are presented in the table below.

Variable	Description	Value	Source/Note
q	Total barrels produced (thousand bbl/year)	147,387	FY2021 Forecasted Production for Prudhoe (+ Satellites), Kuparuk (+ Satellites, and Alpine
ct	Transportation cost per tax bbl	9.78	FY2021: Chp 4 Table 4
r	Effective royalty rate	11.4%	FY2021 royalty barrels / total barrels
gvr	Effective gvr rate	1.7%	FY2021 GVR / GVPP

The effective royalty rate is calculated as the value of royalty and federal barrels divided by the total gross value ($p*q$). Using the effective royalty rate here simplifies the exceptions to the general 12.5% rate charged to state and federal oil. For the last 5 years, the average effective royalty has been 12.4%, so the FY21 forecast value used is represents a decline. Similarly, the effective gross value reduction rate is used to simplify the complications of identifying and quantifying the actual GVR values. The 1.7% from the FY21 forecast is the highest GVR rate seen in the last 5 years.

Technical Appendix: Annual Revenue Sensitivity to Quantity

The effect of taxes on production should be considered in two time periods. In the short run, the number of operating wells is fixed at some level. Over the long run, new wells or fields come online or others are shut-in. Given the (generally) low marginal cost of production and some costs for shut-in, economists have shown both theoretically and empirically that oil production is relatively price inelastic in the short-run (Anderson et al., 2018). Producers tend not to quickly ramp up or down production when prices change. We might therefore expect similar effects from tax changes.

How long is the short-run? The full exploration and development cycle takes many years bring new production online, and even shutting in a well is not instantaneous. These lag times imply that the short run may be months or years. However, it is important to recognize that at any time different projects will be at different stages of development. Projects close to commercial production may be delayed or canceled for example bringing about the "long run" in a matter of months.

When considering potential effects of changing prices or taxes on oil production, it is important to distinguish between these two timeframes. Theoretical and empirical economics suggests minimal short run changes, but more meaningful long run effects. So, while BM1 may bring about the full incremental revenue estimated in the static analysis over one or two years, in the long run the incentive effects will put downward pressure on investment.

With these considerations in mind, we ask, how much production would need to decline in order for the incremental state revenue raised from BM1 to be completely offset? For this analysis to be meaningful, both production taxes and royalties must be considered. Property taxes and cooperate income tax will be ignored for simplicity, because historically they make up a smaller fraction of overall state revenue, and because property tax will be invariant to production changes in the medium term. However, this limitation should be noted.

As in the static revenue model, let *r* be the effective royalty rate. Let *sr* be the share of royalty barrel value that becomes unrestricted state royalty revenue (including bonuses, rents, interest, and federal royalty share). State unrestricted royalty revenue as a function of oil price and quantity is then *p*q*r*sr*.

The incremental total revenue under different production scenarios under BM1 is calculated:

$(TaxRate_{BM1} + r*sr)*p*q_{BM1} – (TaxRate_{statusquo} + r*sr)*p*q_{statusquo}$

Where $TaxRate_{BM1}$ is the effective tax rate under BM1, *r*sr* is the state's effective royalty rate, q_{BM1} is the quantity of oil produced under a given reduced production scenario, $TaxRate_{statusquo}$ is the effective tax rate under the status quo and $q_{statusquo}$ is the forecast annual oil production assuming no changes.

The following values are used to calculate the state's total oil revenue under the status quo scenario.

Variable	Description	Value	Source/Note
p	Price of oil delivered ($/bbl)	40	FY21 Spring forecast price, rounded to nearest $10
cl	Avg Lease Cost ($/tax bbl)	29.02	FY21 Chp 4 Table 4
q	Total barrels produced (thousand bbl/year)	150,000	FY21 40/400 production rounded to nearest 10mbbl/yr
ct	Transportation cost per tax bbl	9.78	FY2021: Chp 4 Table 4
r	Effective royalty rate	0.11	FY2021 royalty barrels / total barrels
sr	State share royalty	97%	State Royalty Revenue/ Royalty Barrel Value
gvr	Effective gvr rate	2%	FY2021 GVR / GVPP

Using the values specified for the status quo and BM1 case, BM1's incremental revenue is estimated for production levels from the 40/400 areas over a range of 150m barrels per year (the current level) to 75m barrels per year. In the Table below, BM1 is estimated to breakeven at a decline in production of 30-45 million barrels or 20%-30%. In other words, if BM1 does induce producers to curtail production, it would need to induce curtailment of 30-45 million barrels worth of production to be a net loss to state revenue. Incorporating corporate income taxes would shrink this breakeven curtailment somewhat.

To put these production scenarios into context, over the six year period of 2012/2013 to 2019, production in the 40/400 areas declined from 180 million barrels per year to 150 million barrels per year. Similarly, AK DOR's Fall forecast estimates production will decline 30-45 million barrels by approximately 2028. So, declines in production on the order of 30 million barrels per year last occurred over a 6 year period, and will next occur over an 8 year period.

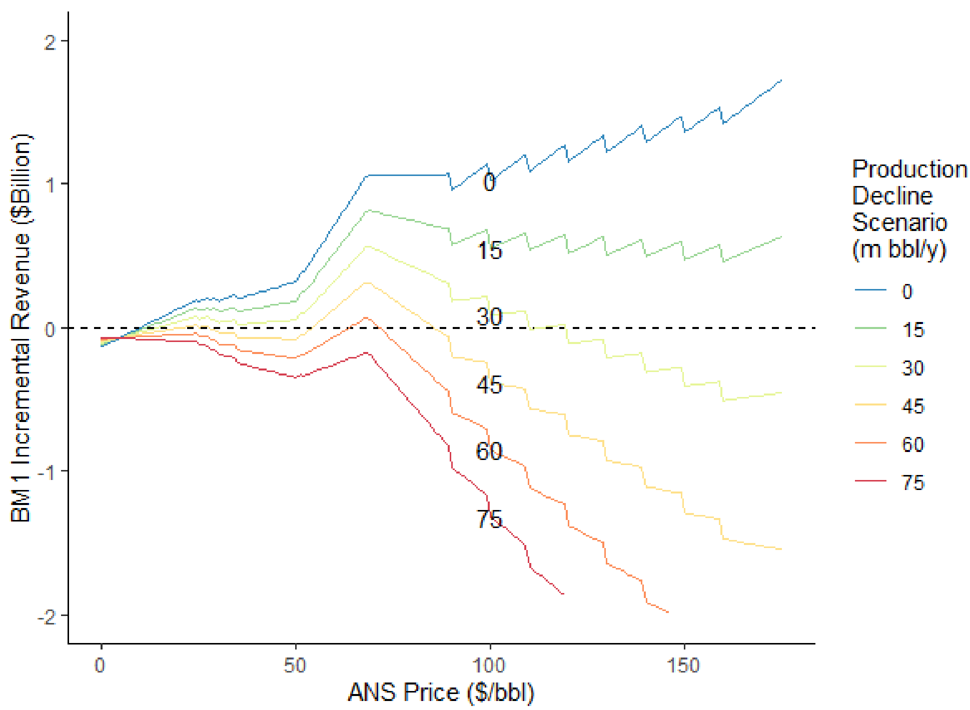
The Figure presents the incremental effects of BM1 with various production scenarios and oil prices. The various kinks in the relative tax schedules produce some non-linear effects. At prices between $50-80/bbl, the breakeven quantity is larger than it is at prices between $35-50/bbl, and prices greater than $100/bbl. In other words, the tax is more likely to provide a net increase in state revenues (given unknow production reductions) at prices slightly lower or slightly higher than the current $40/bbl forecast.

BM1 Incremental Revenue Sensitivity to Production Levels

Scenario				Status Quo	BM1			
q (million bbl/y)	Change in q	Years	% Change	Production Tax + Royalty = Total ($m)	Production Tax ($m)	Royalty ($m)	Total ($m)	Incremental Revenue ($m)
150	0		0%		403	642	1,046	242
135	15	4-5 yrs	-10%		363	578	941	137
120	30	6-7 yrs	-20%	161 + 642 = 804	323	514	837	33
105	45	9 yrs	-30%		282	450	732	(72)
90	60	10 yrs	-40%		242	385	627	(176)
75	75	>10 yrs	-50%		202	321	523	(281)

BM1 Incremental Revenue under various production scenarios (q), relative to status quo production and taxes. Change in q is the difference between status quo production of 150mbbl/y and the specified scenario. Years counts the number of years prior to 2019 required to find a decline by as big as a given scenario (i.e. between 2014 and 2019, annual production declined by approximately 15 million, between 2012/13 and 2019 annual production declined by 30 million). In the status quo scenario of 150million bbl and a $40/bbl price, total state revenue from 40/400 areas from production taxes and royalties will be and estimated $804 million. Given the specified level of production and the same prices, BM1 would generate the estimates levels of production tax, royalty and total revenue indicated. The difference between total BM1 revenue by scenario and $804m is shown in the final column.

Dynamic Incremental Revenue, No Ringfence Effects



Source: Author's calculations of additional revenue from BM1 considering dynamic effect scenarios across prices. Effects of ringfencing are not considered here. Shown are the net effect on annual revenue if BM1 caused production declines of 0-75 million barrels per year.

Providing Additional Context to Production Declines

Brown, Maniloff, and Manning (2020) estimates the responsiveness of drilling activity to changes in severance taxes in the same state. They compare drilling activity a given oil field that stretches across the border between two states and compares drilling on each side when taxes change in one state. This complicates extrapolating their estimate to the context of BM1, as no oil field effected by the measure extends into another state's jurisdiction. In communication with the authors, they suggest their estimates may be interpreted as an upper bound for the effect of the tax increase in Alaska.

With these important limitations noted, Brown, Maniloff, and Manning (2020)'s main specification estimates that a $1 increase in severance taxes per barrel decrease the number of wells drilled annually by 8%. Under prices of $40 per barrel and lease costs of $30 per tax barrel, BM1 would increase severance taxes by $1.60 per barrel, implying a 12.8% decrease in annual wells drilled.

These potential reductions in drilling have two important implications. First, they will reduce future production and resulting state revenues. Second, much of the employment impacts from oil and gas come from the exploration and drilling activities, rather than the annual production of oil. We provide some additional estimates for these to effects.

The Alaska Oil and Gas Conservation Commission provides information on drilling activity in and outside the 40/400 areas. In 2019, there were 1,791 oil producing wells in the 40/400 area, will 59 new wells completed. The number of newly drilled wells has been declining over time in the 40/400 areas. For reference in 2000, there were 106 completions. The number of new wells drilled declined by an average of 6.6% per year between 2000 and 2009 and 7.5% between 2010 and 2019. In the status quo scenario, it is unclear whether the declining drilling trend will level, continue apace, or further accelerate.

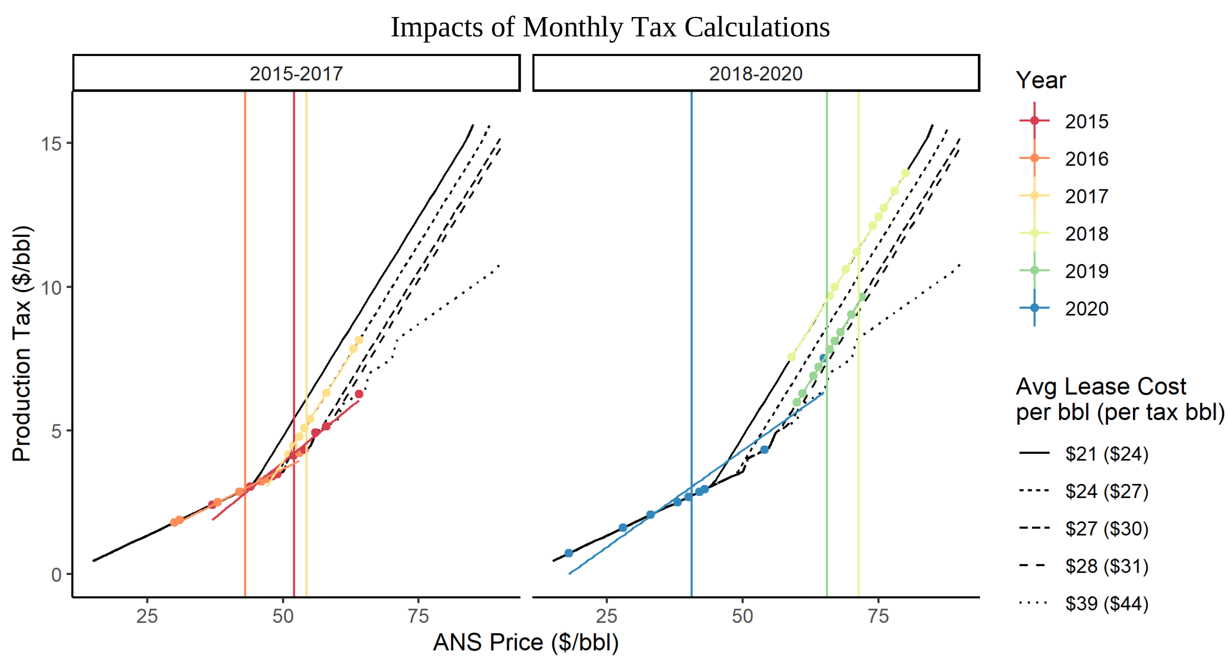
Again, noting the limitations of extrapolating the estimate from Brown, Maniloff, and Manning (2020), at current prices and lease costs BM1 might reduced drilling activity on the order of 13%. Using a baseline of 53 wells, the average number drilled annually between 2015-2019, translates to roughly 7 undrilled wells per year as a result of BM1. If declines in drilling activity continue at the same pace as observed over the last decade, the number of implied 'undrilled' wells decreases, as they would be calculated from a reduced baseline.

In translating drilling into production, it is important to recognize that new wells are more productive than existing wells. Between 2015 and 2019, the average well in the 40/400 area produced and average of 65,000 barrels of oil per year. Contrast this with a new oil well drilled in the 40/400 area, which has averaged 146 thousand barrels of oil production per year over the first three years of its life. Foregoing a drilled well today has larger implications in the first few years than in later years.

If BM1 were to reduce drilling by 7 wells in its first year, a rough approximation implies that 1,022 thousand barrels of production might be forgone each year for these 7 wells, averaged over a three year time frame. Totaled over 3 years, this implies 42 well-years worth of missing first year production, or 6.13 million barrels. For the Fall 2019 Forecast, DOR projects production from the 40/400 areas of 435.1 million barrels between 2021-2023. So in the scenario outlined here, this translates into 1.4% reduction in production over three years.

Technical Appendix: Graphical Analysis of Monthly Tax Calculation

The Figure helps to explain the mechanics of the monthly tax calculation by plotting the monthly prices (points) and average annual prices (vertical lines) over the corresponding tax schedules given average lease costs in a given year. When prices only fluctuate in one portion of the tax schedule, the monthly v annual destitution makes no difference as in 2018 and 2019. In these years, prices would have been sufficiently high (and lease costs low) to always induce the net tax (35%) rather than minimum tax payments (10%-15%). When prices are more volatile, particularly around the threshold between the minimum and net taxes (or when lease cost cause the higher min tax rates to phase in), the monthly tax calculation makes a larger impact.



Source: Author's calculations. Vertical lines are average annual prices each year. Points are average monthly prices. Black lines are the tax schedule given the average lease cost in the corresponding year. Diagonal colored lines are the best fit of the monthly price points, the slope of which is equal to the effective average tax rate using the monthly calculation. When the colored line is steeper than the corresponding slope of the black tax schedule where the same colored vertical line intercepts the tax schedule, the monthly tax calculation produces a higher effective tax rate than the annual calculation.

Technical Appendix: Decade Analysis

This section provides details for the two analyses conducted in the decade ahead forecast. The first is the analysis that assumes producers do not respond to the tax by changing the trajectory of production over the next decade. The second attempts to model how changing producer behavior would affect State revenue collections.

Potential Revenue: Over a Decade

The decade analysis builds on the single year, static model described previously. Each year, the total and incremental revenues are calculated using the tax model and the forecasted parameter values in the given year. The two key sources of parameter values are price forecasts from the AK DOR 2020 Spring Forecast and all other values come from the AK DOR 2019 Fall Revenue Sourcebook. The table below reproduces these values and describes their calculation.

	Daily Production (K bbl/day)			ANS Price ($/bbl)			Other Parameters				
Year	Prudhoe	Kuparuk	Alpine	Base	Low	High	ct	cl	r	sr	gvr
2020	248.4	103.1	54.2	51.65	44.34	61.73	9.06	36.74	0.115	0.967	0.02
2021	247.3	99.6	56.9	37.00	23.34	59.31	9.78	41.15	0.115	0.967	0.02
2022	234.3	98	50.2	41.00	25.57	65.00	10.17	45.15	0.115	0.967	0.02
2023	221.6	93.2	44.9	44.00	27.61	70.17	10.59	45.66	0.115	0.967	0.02
2024	210.8	86.6	43.4	46.00	29.04	73.82	10.46	44.94	0.115	0.967	0.02
2025	201.1	93.1	42.3	48.00	30.03	76.34	10.31	42.92	0.115	0.967	0.02
2026	192.5	82.6	39.2	49.00	30.87	78.47	10.45	40.03	0.115	0.967	0.02
2027	184.9	76.9	34.8	50.00	31.26	79.47	10.62	37.24	0.115	0.967	0.02
2028	177.9	72.6	30.8	51.00	32.14	81.68	10.68	35.46	0.115	0.967	0.02
2029	171.3	68.9	28	53.00	33.18	84.35	10.83	34.27	0.115	0.967	0.02
Average Decline	4.04%	4.26%	4.92%								

Sources: DOR Spring Forecast prices. Other values calculated from Fall 2019 Revenue Sourcebook. Prudhoe and Kuparuk daily production in thousand barrels per day include their respective satellite fields. Lease costs, cl is calculated by dividing total statewide lease expenses by the quantity of taxable barrels. We assume the effective royalty rate (r) the State's share of effective royalties (sr) and the effective gross value reduction (gvr) remain fixed over time at their 2021 levels. Average decline is the simple year-over-year average rate of decline in the respective fields.

Potential Revenue: What if Taxes Cause Production Decline to Accelerate?

Understanding the incremental revenue impacts of production responses to the tax change requires assumptions to model an appropriate counterfactual. This analysis will make four key assumptions:

1) Like the single period analysis, we assume that the average statewide values for average lease costs and other important values are good approximations for those specific to the 40/400 areas. Average lease costs are likely lower in the 40/400 areas. Reduced lease expenditures cause the higher net tax to kick-in at lower prices. However, if 40/400 expenses are lower, on average, that implies expenses outside are higher causing pushing down the production tax value of all other fields toward the minimum tax floor or getting carried forward as losses.

2) Second, despite the source of declining production being driven by reductions in investment, we assume that nevertheless (1) capital and operating costs are the same both in the status quo and BM1 cases. This assumption underestimates the potential revenue from BM1 because if lease costs we lower, the net tax value would be larger and apply at lower prices.

3) Given the complexities of corporate income or property tax, the potential impact of declining production is not determined for them. However, property taxes are less sensitive to the level of production than other taxes, so this assumption is likely valid. Similarly, corporate income tax revenue is likely to be small in absolute terms for the 40/400 area producers.

4) We assume that the only behavioral response to BM1 occurs inside the areas currently covered by the 40/400 threshold. However: a) The ringfence provision will likely force some companies to carry forward expenses outside the 40/400 areas instead of deducting them contemporaneously. This will likely have negative impacts on certain project economics outside the 40/400 areas. b) There is also a budget effect.

The transfer of rents from the firms to the state will reduce the amount of capital that firms have to invest both in 40/400 and non-40/400 areas. c) Finally, BM1 shifts the relative rate of return between the 40/400 and non-40/400 areas, meaning that it could shift some investment from inside to outside the areas it directly affects. The ringfencing and budget effect will bias our estimate upward (it will be too high), while the shift-incentive effect will bias it downward, therefore the net effect of these caveats is ambiguous.

In ever year, and at each given rate of decline, the model determines whether a particular field meets the 40,000 barrel per day threshold required for a field to be subject to the BM1 tax. In the status quo scenario, Alpine is not subject to BM1 after 2025. As the production rates of decline increase under our alternative scenarios, this date is shifted forward. At sufficient production decline scenarios (if decline were to accelerate 6 percentage points, from 4.26% per year to 10.26%), Kuparuk also becomes in-eligible for the BM1 tax within the 2021-2029 timeframe.